COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

BOSTON GAS COMPANY d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND	)	**D.T.E. 03-40**

REPLY BRIEF OF THE MASSACHUSETTS ATTORNEY GENERAL

Respectfully submitted,

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September 17, 2003

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I. INTRODUCTION

Pursuant to the procedural schedule issued by the Hearing Officer, the Attorney General files this Reply Brief for the purpose of responding to arguments made in the Initial Brief submitted by the Boston Gas Company, d/b/a KeySpan Energy Delivery New England ("Boston Gas" or "Company") in this proceeding on September 10, 2003. This brief is not intended to respond to every argument made or position taken by the Company. Rather, it is intended to respond only to the extent necessary to assist the Department of Telecommunications and Energy ("Department") in its deliberations, i.e., to provide further information, to correct misstatements or misinterpretations, or to provide omitted context. Therefore, silence by the Attorney General in regard to any particular argument in another party's brief should not be interpreted as assent.[1] The Company makes several arguments in the "Introduction" to its initial Brief. These issues are addressed below.

[1] The Company has baldly stated that it "will not respond to all of the issues raised by DOER and the Attorney General in this initial brief and will address remaining issues in reply." Co. IBr. at 178. Given that such a position is inconsistent with the Department's briefing schedule and fundamental fairness, the Company has waived its right to brief any such "remaining issues." Should the Company address such issues contained in parties' initial briefs, the Attorney General reserves his right to respond to the Company's Reply Brief. G.L. c. 30A § 11(1).

II. THE DEPARTMENT SHOULD DENY THE COMPANY'S PROPOSED RATE INCREASE BECAUSE THE CHOSEN TEST YEAR IS FRAUGHT WITH ACCOUNTING VIOLATIONS.

The Company claims that the Attorney General did not identify any specific accounting errors and that the Company " ... recorded all costs in accordance with the Department's Uniform System of Accounts." Co. Br., p. 9. To the contrary, the record shows that the Company inappropriately:

(1) combined the books of Essex County Gas Company, a separate and distinct regulatory entity, with those of Boston Gas Company, rendering the information on both companies Annual Returns to be useless (Exhs. KEDNE/PJM-2, AG-11-1 and KEDNE/PJM-1, p. 21);

(2) recorded costs to Account 922 --- Administrative Expenses Transferred -- Credit, that are not appropriately charged to that account. Exh. AG-23-14; and

(3) booked Service Company costs to the Boston Gas Company's Administrative and General cost accounts rather than to those accounts to which those costs relate. Exh. AG-31-6.

These accounting violations, collectively, render the Company's test year cost of service useless for setting distribution rates. The Department should therefore deny the Company's proposed rate increase in total. Furthermore, the Department should order the Company to bring its accounting into compliance with its Uniform System of Accounts with regard to each of these items.

Separate from the issue of the reliability of the proposed test year in this case, the Attorney General has prepared cost of service schedules that determine a pro forma revenue requirement based on the corrupted test year information. *See* Attachments to this Reply Brief. Based on appropriate pro forma adjustments to the test year revenues and costs, these schedules show that the Company, in fact, has a revenue **surplus** and not a revenue deficiency as it claims. Therefore, if the Department decides that the test year financial information can be resuscitated and made reliable, the Department should reject the Company's cost of service analysis and, instead use those pro forma adjustments proposed here and in the Attorney General's Initial Brief, find that the Company has a surplus and reduce customers rates accordingly.[2]

[2] The cost of services schedules attached to this brief do not include the reduction in the costs associated with the removal of the entirety of the Service Company charges. If the Department removes all of those charges, which are in excess of $85 million, the cost of service will again show that the Company has a revenue surplus (even without any other adjustments the Company's pro forma cost of service). Exh. KEDNE-2, p 41, Revision 2. The Attorney General cannot determine the additional pro forma reduction in the cost of service to remove all of the Service Company charges at this time. If the Department finds that all of the Service Company charges should be removed, it should order the Company to provide the calculations of the necessary adjustments to the cost of service to effectuate that change in the Company's compliance filing to this case.

III. THE COMPANY'S TIMING OF INVESTMENTS TO COINCIDE WITH TEST YEARS WILL RESULT IN UNDULY INCREASED RATES.

The Company argues that the timing of capital spending is irrelevant. It maintains that, under standard Department ratemaking precedent, all capital investment through the test year is eligible for inclusion in rates. Co.IBr. at 7. Delayed capital investment, however, can harm consumers, and capital investment accelerated into a test year raises cast-off rates.

The Company's own records show that the Company "loaded the test year." Exh. AG-1-17. Compared to the years 1996-2000, Boston Gas approximately doubled the amount it spent on utility plant in the year 2002, the "test year" in this case. The Company almost tripled spending in 2001, the "test year" for the rate case the Company planned to file, but then abandoned. Tr. 12, pp.1540-1544; Exh. AG-21. The Company's previous price cap plan ended in 2001 and the Department had ordered the Company to file a successor plan in that year. Exh. AG-21.

Year	**Total Gas Plant Additions**
2002	$128 million Test year in this case
2001	$149 million End PBR plan from D.P.U. 96-50 Company's abandoned test year
2000	$ 60 million
1999	$ 52 million
1998	$ 51 million
1997	$ 57 million
1996	$ 55 million

Exh. AG 1-17 (1998-2000 annual returns to Department).[3] *See also* Exh. DTE 4-16 (1995-2002 mains and services spending); Exh DTE 4-43 (1995-2002 cast iron placement schedules).

The Company claims that there is "no evidence" that it failed to prevent leaks or system deterioration on 1,500 streets. Co. I.Br at 7. The Company does not, however, also explain that there is "no evidence" because it either destroyed, lost, or failed to retain the system modeling reports on these streets for the years prior to the repairs. Those reports, which the Company could not produce in response to information requests, should have documented the history of the system low-pressure. Tr. 12, pp. 1224-1227; RR-AG-49, AG-55-50; Tr. 21, pp. 2787-2795; RR-AG-76. Even in the absence of these reports, it is not reasonable to assume that all 1,500 streets suddenly needed repair after 2000. The Department requires the Company to maintain adequate business records, 20 C.M.R. §75.00 (record retention regulations), and in light of the other record evidence of delayed capital investment, the Department should draw a negative inference from the Company's failure to provide documentation of system pressure for the years immediately before the extensive upgrade.

Second, delaying capital investment reduces depreciation between test years, and therefore leaves higher test year-end net plant in service as a result of the accumulation of the depreciation and the associated deferred income taxes, causing higher rates to customers. A reasonably timed schedule of plant improvements should also result in (a) lower maintenance costs (physical plant) and (b) higher productivity (systems, hardware). Delaying implementation of plant improvements reduces these benefits to customers.

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[3] Pursuant to 220 C.M.R. §§ 1.10(2) and (3) the Attorney General asks the Department to incorporate by reference or take administrative notice of the gas plant additions in the Company's annual returns for 1996 and 1997. The 2000 gas plant figure is adjusted to remove the recorded acquisition premium.

The Company's hybrid test year proposal results in multiple, unwarranted costs for the Company's customers. During the five years before the test years, the Company enjoyed higher profits under the old PBR by delaying plant improvements as customers paid automatically-increasing rates for service from an aging system. The Company now wishes to use a loaded test year to re-establish cast-off rates for a new PBR plan, and then automatically escalate these rates. Scheduling maintenance to coincide with the test year in this manner perpetuates harm to consumers under the PBR and revives overbuilding of plant within a test period, one of the perceived flaws of cost of service ratemaking. Modern incentive plans, including a PBR, are supposed to eliminate this flaw by breaking the link between costs and rates. *See Incentive Regulation*, D.P.U. 94-158, pp. 55-57 (1994). The Department should avoid the Company's attempt to frustrate the purpose of incentive ratemaking and set a reasonable level of plant additions.[4]

[4] The average plant investment during the years 1996 through 2000 was $55 million: [($60 + $52 + $51 + $57 + $55) / 5 = $55]. *Id.* Therefore, the extra investment during the years 2001 and 2002 was $167 million: [($128 - $55) + ($149 - $55) = $167]. *Id.* Had those extra dollars been spread over the entire seven year period, it would have impact each year by approximately $24 million: [$167 / 7 = $24]. *Id.* With the additions being approximately 40 percent services with a depreciation rate of 8.63 percent and approximately 60 percent mains with a depreciation rate of 2.49 percent the weighted average depreciation rate would be 4.95percent: [0.40 x 0.0863 + 0.60 x 0.249 = 0.0495]. See Exh. DTE 4-16 and Exh. KEDNE-PJM-2, Supplemental, p. 158. So for each year of additional capital investment there would have been an additional $1.2 million of accumulated depreciation for each year it was in service. [$24 million x 4.95 percent]. Therefore, the 1996 additions would have accumulated 6 years worth of depreciation or $7.2 million [$1.2 million x 6], the 1997 additions $6 million [$1.2 million x 5], the 1998 additions $4.8 million [$1.2 million x 4], the 1999 additions $3.6 million [$1.2 million x 3], and the 2000 additions $2.4 million [$1.2 million x 2], for a total of $24 million in accumulated depreciation during that period. This amount would have been deducted from rate base, along with the associated balance of accumulated deferred income taxes.

IV. THE COMPANY FAILED TO MEET ITS BURDEN TO SHOW "NO NET HARM" FROM THE KEYSPAN MERGER.

The Company argues that the KeySpan / Eastern Enterprises merger, as a merger of holding companies, did not require Department approval under G. L. c. 164, §96. Co.IBr. at p. 7. The Company also claims that it does not seek the recovery of merger related costs from the customers of Boston Gas, and that the Company shared in the alleged $55 million in savings resulting from the KeySpan merger. *Id.* The Company generally dismisses the Attorney General's arguments that the Department should examine the KeySpan Service Company ("Service Company") affiliate contracts from the merger, the merger debt pushdown or the gas portfolio management and purchase gas contracts, which together make up over two-thirds of the Company's test year costs. Co.IBr. at 8.

When evaluating a rate plan filed by a company, this Department can - and should - review any costs affecting base rates that result from a merger, even if was a merger of holding companies, otherwise not subject to review. The Company, however, does not address this relevant Court precedent on merger approvals. In *Attorney General v. Department of Telecommunications and Energy*, the Court upheld the Department's application of the "no net harm" standard from G. L. c. 164, §96, by analogy to a rate plan filed under G. L. c. 164, §94, related to the ***merger of holding companies***. AGIBr. at 9-10. *See Attorney General v. Department of Telecommunications and Energy*, 438 Mass. 256, 268-269 (2002).

In a merger review case the Department employs a multi-factored balancing test:

> In considering this proposal, the Department's analysis focuses on the following factors: (1) effect on rates, resulting net savings and alternatives to merger; (2) effect on the quality of service; (3) societal costs; (4) effect on competition and

economic development; (5) cost allocation; (6) transaction and merger integration costs; and (7) acquisition premium.

Eastern / Essex Merger, D.T.E. 98-27, p. 10 (1998). The Company has not explained why the Department, in reviewing the rate plan under similar circumstances, should not evaluate the costs and benefits of the merger to customers, under the doctrine of reasoned consistency. *Boston Gas Company v. Department Public Utilities*, 367 Mass. 92, 105 (1975).

Second, the Company seeks to recover both direct and indirect costs from the KeySpan merger with Eastern Enterprises, although the Company claims otherwise. Co.IBr. at p. 7. The Department typically considers and allows various systems integration costs necessary to achieve merger saving when conducting its "no net harm" analysis. *Eastern / Essex Merger*, D.T.E. 98-27, p. 7. Here, the Company seeks to recover over $20 million in direct costs for systems integration caused by the change from[5] the Boston Gas' CSS customer service and billing system to KeySpan's CRIS computer system. KEDNE/PJM-1, p. 46; Tr. 7, p. 838. Boston Gas certainly would not have incurred these costs to change to the KeySpan information technology system if not for the merger.[6]

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[5] The Company recorded on its books $23.6 million of CRIS costs. For ratemaking purposes, it allocates $1.7 million to Essex, leaving a balance of $20.7 million. The Company has included the $20.7 million in its rate base and $2.2 million of related annual amortization expense is included in its cost of service.

[6] The cost of nuclear insurance from one of KeySpan's New York electric affiliates, the Long Island Lighting Company, represents another example, although minor, of the Company improperly attempting to recover costs connected with affiliates of KeySpan from the merger. Tr. 25, pp. 3428 - 3429; RR DTE 110 (Company eventually agrees to remove nuclear insurance costs from the Boston Gas cost of service). If the Company had sought review of the KeySpan merger, the Department could have ordered the adoption of a cost allocation system sufficient to protect the Company's customers from such charges.

The Company also seeks to recover from Boston Gas customers more than $8.7 million in non-incremental costs incurred by the Essex and Colonial Gas Companies. AGIBr. at 9-19. These costs come from the regulatory change to the KeySpan Service Company ("Service Company") model. KEDNE/PJM-3 (Service Company agreements). In its initial brief, the Company did not deny the existence of these costs, but merely argued that the record in this case did not reveal any such costs. Co.IBr. at 7. The record, however, shows that the Company seeks to recover costs , incurred by Essex and Colonial, resulting from the KeySpan merger.

Third, the General Laws of the Commonwealth expressly grant the Department the power to review affiliate contracts and reject all costs from the cost of service that the Department deems unjust. G. L. c. 164, §94B; 220 CMR §12.00 (affiliate transaction regulations).

> In determining whether rates are just and reasonable, the Department may examine affiliate transactions to ensure that dealings between affiliated companies provide direct benefits to ratepayers and that associated costs are reasonable and allocated in a nondiscriminatory manner. G.L. c. 164, s. 76A; *Cambridge Electric Light Company*, D.P.U.92-250, at 78(1993); *Bay State Gas Company*, D.P.U. 92-111, at 134-135 (1992). The Department historically has exercised its obligation and authority to ensure that a company's affiliate costs passed on to the company's ratepayers are reasonable and that ratepayers pay no more than a fair portion of the costs. D.P.U. 92-111, at 136-137; *New England Telephone and Telegraph Company*, D.P.U. 86-33-G at 113-211 (1989); *Oxford Water Company*, D.P.U. 1699, at 10-13 (1984).

Eastern / Essex Merger, D.T.E. 98-27, p. 46. The Company bears the burden of proving that "any payment, charge, contract, purchase, sale, obligation or other arrangement" is reasonable. G. L. c. 164, §94C. The KeySpan affiliate contracts have an indefinite term, and therefore cover a period of greater than one year. KEDNE/PJM-3, p. 3 § 3.2 ("Termination: This agreement shall continue in full force and effect until terminated" by sixty days advance written notice.) Although Boston Gas selects the specific services it receives under this agreement each

December for the following year, KEDNE/PJM-3, p. 27, the contract itself endures until cancelled.[7] KEDNE/PJM-3, p. 3 § 3.2. This agreement has been in effect since January 1, 2002, KEDNE/PJM-3, p. 1, well over the one year period triggering Department review under G. L. c. 164, §94B. Even if this agreement were for a period of less than one year, the Department should weigh this contract in its "no net harm" analysis since it represents a large percentage of costs. The Company has not carried its burden to prove that the Service Company costs are recoverable. AG IBr. at 19-25.

Fourth, the Department must approve purchase contracts covering periods in "excess" of one year. G. L. c. 164, §94A. The Company's three year Gas Portfolio agreement and gas purchase contracts for shorter times function together as a unified whole and form a *de facto* contractual relationship for longer than one year. Tr. 1, pp 41-42; Exh. AG-1-2(B)(1)(a), p. 3. In circumstances where a series of contracts for exactly one year may evade Department review, the Department should exercise its discretion to look at the overall ongoing contractual relationship between the real parties in interest to determine whether G. L. c. 164, §94A, applies. Furthermore, the Department has an independent basis to review these contracts, regardless of their duration, as one factor in its "no net harm" analysis.

Fifth, the Department typically evaluates the impact of the merger on a utility's financial condition when conducting a "no net harm" analysis under G. L. c. 164, §96. *Fall River / Southern Union Merger*, D.T.E. 00-25, p. 21 (2000). KeySpan pushed $650 million dollars in

[7] The Attorney General notes that in June 2003, the Company filed an updated agreement to reflect KeySpan's sale of Midland Enterprises, Inc. and the apparent renaming of The Houston Exploration Company. In all other respects, the contract is identical to the 2000 agreement, including §3.2, which states that the contract endures until cancelled.

merger debt onto the books of Boston Gas. Although the Company claims to have removed direct costs of the debt, this debt will remain on the Company's books for an indefinite time and interfere with the Company's ability to issue new debt or refinance. The Department can apply the "no net harm" standard of §96 by analogy to the merger of holding companies. The Department, therefore, should evaluate the debt push down and its impact on the Company and its customers. (*See Attorney General v. Department of Telecommunications and Energy*, 438 Mass. at 268-269).

Finally, the Department requires a demonstration of savings to offset the costs and other burdens imposed by a merger. *Colonial / Essex Merger*, D.T.E. 98-128, pp.4-7 (1998). "A §96 petitioner that expects to avoid an adverse result cannot rest its case on generalities, but must instead demonstrate benefits that justify the costs . . .." *Id*. (citation omitted). For the KeySpan merger, KeySpan distributed the $55 million in alleged cost savings from the merger across the whole KeySpan "enterprise" and the Company could not assure the Department that Boston Gas shared any of these savings. Tr. 22, pp. 2986, 2990-2991; *see also* Exh. AG. 3-7, Exh. 3-11 (Company not tracking actual merger savings from Essex and Colonial mergers); Exh. DTE 6-1 (Company not tracking cost savings); Tr. 12, pp. 1533-1535 (Company does not track cost savings by category and does not understand capital cost savings); Tr. 22, p. 2968 (Company incapable of tracking savings by category).[8] The Company's vague statement of merger savings is precisely the type of generalization that will not help the Company meet its burden of proof in

[8] Since the Company does not track savings by cost category, it is impossible for the Company to focus its resources in areas where savings can be achieved and productivity enhanced. The Department should order the Company to develop an appropriate savings tracking mechanism to identify areas of actual savings, as well as to track actual merger savings from the Essex, Colonial and KeySpan mergers, rather than mere projections or proxies.

the absence of any concrete proof that Boston Gas enjoyed any net savings from the merger. *See e.g. In Re KeySpan Corporation Securities Litigation*, 2003 WL 1702279 (E.D.N.Y.) at *2 (securities fraud class action in New York claimed that any of the $24 to $29 million in projected savings from the merger with Eastern Enterprises were offset by regulatory restrictions and the increased costs of regulation KeySpan would experience under the Service Company model).[9]

V. THE DEPARTMENT SHOULD EXCLUDE KEYSPAN'S ALLOCATION TO BOSTON GAS OF AFFILIATES' NON-INCREMENTAL COSTS.

Boston Gas asserts that "there is no basis for the claim that the Company somehow has a burden to show savings as a result of the Essex and Colonial mergers." Co.IBr. at 73. Even if the Company correctly predicates that argument and its proposed incremental cost adjustments on the Department's decisions in D.T.E. 98-27 and 98-128 -- which it does not -- circumstances have so radically changed since the KeySpan merger and the creation of the Service Company that they merit a fresh look at these issues by the Department. *Boston Edison Company*, D.T.E. 98-119, p. 46 (1999) ("significant or material change in circumstances may warrant a departure from a previous ruling or determination"); *Boston Edison Company v. Department of Public Utilities*, 419 Mass. 738, 747-748 (1995); *Stowe v. Bologna* , 32 Mass. App. Ct. 612, 616 (1992) ("administrative decisions, even if adjudicatory in the sense that they determine rights and duties of specifically named persons, frequently have a regulatory component that may warrant

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[9] The court dismissed part of this class action suit by reasoning that the information on file with the Securities and Exchange Commission ("SEC") put the public on notice of any increased costs of regulation under the Service Company model, and the effect this added regulatory burden would have on ultimate savings from the KeySpan and Eastern merger. *In Re KeySpan Corporation Securities Litigation*, 2003 WL 1702279 (E.D.N.Y.) at *2, 18.

reexamination in the light of changes in regulation, purpose, later decisional law, or applicable on-the-ground facts.") With a fresh look at the incremental cost issues from *Essex* and *Colonial* in the context of the KeySpan merger, the Department should deny the Company's proposal.

Clearly, Boston Gas does have a burden to show that the companies' actions maintain the status quo under the orders in D.T.E 98-27 and 98-128, and that savings have resulted from the Essex and Colonial mergers. *Eastern / Essex Merger*, D.T.E. 98-27 (1998); *Colonial / Essex Merger*, D.T.E. 98-128 (1998). The Attorney General maintains that the Company has failed to meet this burden. Indeed, the analysis presented by the Company in RR-AG-101 shows that the expenses incurred by Boston Gas have increased from the time prior to the Essex and Colonial mergers until the test year in this case. The available evidence , then, suggests that there are no savings that might validate the incremental cost adjustment.

If there have been no savings as a result of the Essex and Colonial mergers, and in particular if there have been no savings to Boston Gas from economies of scale, then, by definition, the expenses recorded by Boston Gas on its books of account must be at least as great as the expenses that would have been incurred in the absence of the merger. There is no dispute that the effect of the incremental cost adjustment is to increase the expenses included in the Company's revenue requirement. As the cost of service prior to the incremental cost adjustment does not reflect any merger savings, then the cost of service with the incremental cost adjustment must, as a matter of mathematics, be greater than the cost of service in the absence of the mergers. In effect then, absent any savings from the Essex and Colonial mergers, the incremental cost adjustment causes the mergers to result in net harm (increased revenue requirement) to Boston Gas ratepayers.

The Company goes on to claim that, "Under the construct approved by the Department, all of the savings attributable to Essex and Colonial reside with those companies." RR-AG-101.[10] If by this the Company means that savings attributable to the merger are already reflected on the books of those companies, then the incremental cost adjustment is unnecessary, as the investors are already retaining the benefits of such savings prior to the incremental cost adjustment. In the final analysis, unless the mergers resulted in savings to Boston Gas, then the incremental cost adjustment results in a violation of the Department's enunciated standard of "no net harm" to ratepayers from the mergers in D.T.E. 98-27 and 98-128.

The record does not show that "the Company has applied a fair and reasonable criteria [sic] by which to evaluate cost entries and has methodically applied that strategy" to the incremental costs. To the extent that administrative and general expenses such as finance, human resources, legal, and corporate management were not directly assignable, KeySpan simply deemed them to be "non-incremental" and allocated them to Boston Gas for ratemaking purposes. There is no evidence that the Company conducted any study or analysis of these costs to determine the extent to which they are actually non-incremental and could not be assigned to Essex or Colonial. The Company, in effect, simply declared, without analysis, these expenses were non-incremental and therefore recoverable from Boston Gas ratepayers. It should be self-evident that activities such as tax preparation, property management, human resources, and purchasing will be greater as a result of the addition of Essex and Colonial than without those companies. To paraphrase the Company, it is simply not enough just to state that finance, human

[10] The Company did make certain selective adjustments that resulted in savings. The Department should review these adjustments carefully because the Company has not given a reasonable basis for including these particular adjustments.

resources, legal, purchasing, and property management are non-incremental and include all of those expenses in the Boston Gas revenue requirement.

The Company claims that the analysis presented in RR-AG-101 demonstrates that its O&M expenses have not increased from the time prior to the Essex and Colonial mergers to the 2002 test year in this case. As pointed out in the Attorney General's initial brief, it is only after the Company selectively eliminates the expenses that have increased the most since the 1996-1998 time frame that RR-AG-101 supports such a conclusion. AG IBr. at 17.

The Company eliminates only those expenses that have shown the most growth in its analysis, and has not provided a rationale for not eliminating certain other expenses with less impact. For example, if the Company eliminates pensions from the analysis, then it makes just as much sense to eliminate other employee benefits. In addition, the Company should also eliminate uncollectible accounts expense, which is a function more of revenues and extraneous economic conditions than it is of the Company's operational methods. With those further adjustments, the expense comparison presents a different picture:

GAS OPERATION AND MAINTENANCE EXPENSES ($000)

	2002	1998	1997	1996	3YR AVG.	Variation
Gas O&M, RR-AG-101 at 4	131,503	115,737	134,801	132,777	127,772	3,731-3%
Other Employee Benefits	10,456	15,109	17,355	18,937	17,134	(6,678)-39%
Uncollectible A/C	6,290	12,950	13,221	13,947	13,373	(7,083)-53%
Net Gas O&M	114,757	87,678	104,225	99,893	97,265	17,492-18%

With other employee benefits treated the same as pensions and uncollectible accounts eliminated from the analysis, operation and maintenance expense has increased by 18% (well in excess of any allowance for inflation and system growth) from the 1996-1998 time frame until the test year in this case. Any fair reading of the data presented in RR-AG-101 indicates that the Essex and Colonial mergers have not resulted in any savings from economies of scale.

As explained above, absent such savings, the incremental cost adjustment results in net harm to Boston Gas ratepayers and should be rejected by the Department. The Company has provided no support for its treatment of these expenses as non-incremental to Boston Gas. The Department should reject the Company's incremental cost adjustment.

VI. RATE BASE

A. THE DEPARTMENT SHOULD EXCLUDE FROM RATE BASE CERTAIN PLANT INVESTMENTS THAT THE COMPANY DID NOT SHOW TO BE REASONABLE AND PRUDENT.

The Company argues that the Department should not exclude from rate base the costs of 16 plant addition projects whose internal rate of return ("IRR") appears to be below its previously allowed weighted cost of capital of 9.38%.[11] Co. IBr. at 23-25. The Company claims that the IRR for 12 of these revenue-producing projects only fell below 9.38% in hindsight, when actual project construction costs exceeded expectations due to circumstances it did not foresee at the outset. The Company notes correctly that the Department determines whether an investment is reasonable and prudent based not on hindsight, but on what the Company knew or should have

[11] The Company cites RR-AG-59 as supporting its assertion that all 16 plant addition projects that fell below 9.38% are justified. That record response, however, addresses only 12 of the challenged projects. Even if the Department finds that the Company adequately explained why the 12 projects' IRR fell below 9.38%, the Company still did not explain the reasons for the remaining four plant additions, which total $1,486,880. The Department cannot determine whether these projects were reasonably and prudently incurred at the outset, and so should remove their costs from rate base. *Boston Gas*, D.P.U. 96-50 at 23.

known or foreseen when it decided to pursue the project. Co. IBr. at 23; *Fitchburg Gas and Electric*, D.T.E. 02-24/25 at 36.

The Company, however, cites no record support for its claims that (1) the initial IRR for each project exceeded 9.38%, and (2) in each case cost increases could not have been foreseen at the outset.[12] The Company inexplicably failed to provide the initial IRRs that it relied on in deciding to pursue these revenue generating plant additions, even when asked, and instead provided its **post**-construction IRRs for these projects. Exh. KEDNE/PJM-10; Exh. DTE-4-31; RR-AG-59. It is the initial IRR, not the post-construction IRR, that is critical for the Department to evaluate the prudence of extant circumstances. *Fitchburg Gas and Electric*, D.T.E. 02-24/25 at 36. The Company's failure to provide the initial IRR precludes the Department from determining whether the Company's decisions to invest in these 16 plant additions were reasonable and prudent prior to construction. Because the Company has failed to carry its burden to show that these 16 plant investments were reasonable and prudent at the outset, the Department should remove their costs, $5,941,000, from rate base.

[12] The Department does not allow parties to testify in a brief to factual matters not supported on the record. *WMECo*, D.P.U. 86-8C-1, p. 23, n.5 (1986); *AT&T*, D.P.U. 85-137, p. 49 (1985); *AT&T*, D.P.U. 91-79, pp. 5-11 (1991); *Verizon Alternative Regulatory Plan*, D.T.E. 01-31-Phase II, Hearing Officer Ruling Granting Motion Of Attorney General To Strike Portions Of AT&T's Brief, December 19, 2002. In the absence of any supporting citation to the record, the Department should strike the portion of the Company's initial brief (the second sentence of the paragraph that begins on page 24 and the penultimate sentence of the section) where the Company makes these two claims.

B. THE COMPANY FAILED TO DEMONSTRATE THAT THE WEST ROXBURY NON-REVENUE PRODUCING PLANT ADDITION WAS PRUDENT.

The Company argues that the Department should not remove from rate base $576,000 for a project cost overrun that the Company did not adequately explain. West Roxbury project #79111; Co. IBr. at 25-26. The record does not include the actual reason for the increase. The Company now inappropriately speculates about the reason in its brief, without record citation, stating that "the work order involves a much larger job than originally estimated and would have likely involved two adjacent projects that were more efficiently accomplished at the same time."[13] Co. IBr. at 26. The Company's explanation, in any event, lacks enough detail for the Department to determine whether the Company fully monitored and controlled project costs. *Boston Gas Company*, D.P.U. 93-60 at 35.

The Company also erroneously contends that Department precedent does not require it to perform cost containment analyses on a project by project basis, only on an overall basis. Co. IBr. at 25. The Department has required review of each project installed since the Company's last rate case and has disallowed those without adequate support:

> In reviewing the investments in main extensions that were made without a cost-benefit analysis, the Company has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. ... The Company must provide reviewable documentation for investments it seeks to include in rate base.

[13] In the absence of any supporting citation to the record, the Department should strike this phrase from the Company's initial brief.

Berkshire Gas Company, D.P.U. 92-210, p. 24 (1992)(Department excluded ten main extension projects from the rate base because the Company failed to provide a detailed analysis of ten projects individually).

The Company's approach would not achieve the Department's purpose in requiring cost containment--to minimize ratepayers' costs. The Company would be free to let large dollar projects (such as West Roxbury) run far over budget, so long as the total amount invested each year remains under the weighted cost of capital.[14] The Department precedent reflects a more logical and more efficient approach that would lead to greater cost savings and requires the Company to apply cost-containment standards consistently, rather than haphazardly. The individual evaluation approach is a disciplined method that creates incentives for the Company to more closely monitor its investments of ratepayer funds. For these reasons, the Department should remove $576,000 for the West Roxbury work order #79111 from rate base.

C. THE DEPARTMENT SHOULD DISALLOW THE CRIS COMPUTER SYSTEM COSTS BECAUSE THE COMPANY HAS NOT SHOWN THAT THEY WERE PRUDENTLY INCURRED.

The Company claims that the Attorney General has not provided a "sufficient basis for a finding of imprudence" of the CRIS costs. Co. IBr. at 27. It is the Company, however, not the Attorney General, that must demonstrate the prudence of its investments and provide proof of that prudence. *Massachusetts Electric Company*, D.P.U. 95-40, p. 7 (1995); *Boston Gas Company*, D.P.U. 93-60, p. 26 (1993); *Massachusetts Electric Company v. Department of*

[14] Despite repeated requests, the Company has not provided any documentation for the $500,000 overrun. Even though the Company admits in its brief that it must respond to questions regarding specific projects, it has failed to do so. Co. IBr. at 26.

Public Utilities, 376 Mass. 294, p. 304 (1978); *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, p. 24 (1967). The Company has not met its burden here. It cites the Department's standards for prudence reviews, but does not point to any record evidence sufficient to support a finding that the Company acted prudently in incurring the $23.6 million conversion costs. Co. IBr. at 26-32.

Nor does the Company address the Department's directive to the Company regarding CRIS's predecessor system, CSS. In D.P.U. 93-60, the Department warned Boston Gas Company and all other companies seeking to add investments to rate base that they must make an affirmative showing of the reasonableness of any rate base addition.

> We caution utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the Company that the expenditures will be disallowed.

Boston Gas Company, D.P.U. 93-60, pp. 25-26 (1993) (specifically addressing the CSS investment). The Department prefaced its analysis of the prudence of CSS by first criticizing the Company for failing to devote more than a paragraph in pre-filed testimony to the significant rate base addition. The Department added, "[w]hen seeking recovery of expenditures, it is incumbent upon companies to present adequate information to the Department in a clear and reviewable manner." *Id.*, p. 25. The Department noted, "... the Company's initial failure to provide sufficient information in its direct testimony regarding its CSS system is particularly troublesome in light of the magnitude of the expenditures involved." *Id.*, p. 25, n. 10.[15]

[15] The Department allowed most of the CSS costs after considering an independent review of the project by management consultants. No such review has been presented here.

The Company claims that it has shown compliance with the Department's requirements of cost containment and quantification of costs and benefits through the pre-filed testimony of Mr. McClellan. Co. IBr. at 28. That testimony, however, was not independent and was very subjective and qualitative, merely claiming that the Boston Gas customer service system was near the end of its useful life and that "...a single customer information system would facilitate customer-service improvements throughout **KeySpan's** different geographic areas" (emphasis added). Exh. KEDNE/PJM-1, p. 47. "**KeySpan** determined that the long-term interest of its customers and the employees assisting those customers, would best be served by the integration of the customer-information and the **system wide** implementation of CRIS" (emphasis added).[16] *Id*. p. 48. The Company does not cite any cost-benefit analysis or cost estimation analysis supporting the decision to convert from CSS to CRIS. The Company did not provide any quantitative analysis of vendor proposals or cost containment standards established for the conversion project. The Company discussed cost containment efforts associated with other non-revenue producing investments, but failed to mention the CRIS system.

The Company responded to discovery seeking "... all documentation, including all internal and external communications regarding any studies or information that quantifies the benefits, if any, for customers of the CRIS system" by providing only a **discussion** of an assessment of technologies and a quantification of "...benefits in terms of the cost of migrating

[16] The Company's support relates to KeySpan benefits. This is particularly troublesome given the lack of any documentation of the original scope of the conversion project. There is no evidence indicating that the costs exclude work done to upgrade or support future upgrades for the benefit of KeySpan's New York utilities. The Department should audit the scope of the project to determine if and to what extent costs were incurred for the benefit of KeySpan companies in addition to Boston Gas, Colonial, Essex and EnergyNorth. See AG IBr. at 31.

the New England companies to the CRIS system versus the cost of purchasing a new system with the same functionality of the CRIS system to replace CSS." Exh. AG-22-9. The Company included no documentation, study or analysis in its response. *Id*.

The Company argues that it has used a "management tool" rather than a cost benefit analysis to assess the costs of conversion verses the costs of upgrading. Co. IBr. at 29-30. The Company claims that the substitution of the management tool is consistent with Department precedent, noting that in the Company's last rate case, D.P.U. 96-50, the Department reviewed and accepted as prudent non-revenue producing capital additions that were primarily hard assets (pipes and equipment). *Boston Gas Company*, D.P.U. 96-50 (Phase I), pp. 19-20. The non-revenue producing investments were supported by evidence that the Company had solicited bids and employed several cost containment measures. *Id.* The Company has not provided any documentation supporting its claims that it employed any management tool to evaluate any phase of the CRIS investment project.

The Department's standard requires more than a general, superficial discussion of decisions made by the Company. The Department was very clear when it addressed these same issues in the context of the CSS investment. The Department has also stated:

> The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The Company must provide reviewable documentation for investments it seeks to include in rate base.

Berkshire Gas Company, D.P.U. 92-210, p. 24. (1992). The Company has provided even less information in this case than it eventually did in D.P.U. 93-60 and less documented support than it provided in 96-50 or this case regarding non-revenue producing plant additions. The Company has failed to comply with the Department's directives and has not carried its burden of proof. The Department should therefore deny recovery of CRIS conversion costs.

VII. REVENUES

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED SPECIAL CONTRACT REVENUE ADJUSTMENTS BECAUSE THERE HAS NOT BEEN THE LOSS OF A LARGE CUSTOMER WITH REVENUE BEYOND THE NORMAL EBB AND FLOW.

The Company argues that its $3.4 million net revenue adjustment for the loss of the Exelon contract revenue is known and measurable and beyond the normal ebb and flow of customers. Co. IBr. at 45-49.

The record does not support either argument. The Exelon contract is still in place. The fact that Exelon has an option to terminate the contract for New Boston Unit 1 or Mystic Unit 7 does not mean that it actually will exercise that option. The Department has repeatedly refused to accept or deny revenue adjustments based on speculation regarding future events. *Fitchburg Gas And Electric Light Company*, D.T.E. 02-24/25, p. 82 (2002) (possible customer self-generation is an insufficient basis for disallowing a revenue adjustment); *Fitchburg Gas And Electric Light Company*, D.T.E. 99-118, pp. 18-19 (2001) (relying on projected construction of water treatment plant did not justify a revenue adjustment).

The Department also should decide whether the purported revenue loss is actually the result of an exchange, discounting service to one customer with whom the Company has other contractual relationships. Service to Mystic 7 generates far more revenue on a per MMBtu basis than the service provided to Mystic 9 under the Distrigas contract. Exh. AG-1-99

CONFIDENTIAL, pp. 465 (Mystic 7) and 355 (Distrigas). The Company has not justified the disparity in revenue levels based on the much lower prices for service supplied by Distrigas.

Even if the loss of a customer were known and measurable, it still is not large enough to warrant a revenue adjustment under Department precedent. The Company characterizes the possible loss of $3.7 million in 2004 as significant in terms of net operating income before taxes, 5.2 percent. Co. IBr. at 48-49. That is not the ratio that the Department has used to measure significance of loss.[17] The Department has compared revenues lost to base distribution revenues in its decisions to adjust lost test year revenues. *Fitchburg Gas and Electric Light Company*, D.T.E. 02-24/25, pp. 80-81 (2002) (revenue loss significant where it constituted approximately 7 percent of base electric distribution revenues); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118 at 18 (2001) (revenue loss significant where it constituted 8.4 percent of total base electric distribution operating revenues). The percentage of revenue allegedly lost here is not nearly as large. The Exelon contract revenues represent only about 1.1 percent of the Company's base distribution revenue request ($3.7 million divided by $338.6 million).

Furthermore, for ratemaking purposes, special contract revenues are treated as offsets to costs, not contributions to shareholder profits. The Company reduces the revenue requirement by its special contract revenues in determining the tariffed classes, base rate revenue requirements. Tr. 6, pp. 707-708. Given the use to which the special contract revenues are put, the significance of any loss should be measured in terms of distribution tariffed rate revenue requirements, not before-tax income. Even if the Department accepts the Company's speculation that it will lose

[17] It is also not the ratio used in the Company's financial statements to disclose significant customers (*e.g.*, no customer generated 2 percent or more of its firm revenues in 2002). Exh. AG-1-2B (1) (a) and Tr. 7, p. 777.

this customer during the rate year, the comparison between contract revenue and base distribution revenue shows that the loss, at 1.1%, is well within the boundaries of normal ebb and flow. The Department should not approve the Company's proposed net revenue adjustment.

VIII. EXPENSES

A. THE COMPANY'S INTANGIBLE PLANT AMORTIZATION IS ASSET-SPECIFIC AND NOT RECURRING.

The Company claims that the Attorney General incorrectly applies Department findings in D.P.U. 96-50 for a non-recurring, extraordinary expense to nine software projects that are recurring, non-extraordinary, intangible plant amortizations. *Boston Gas Company*, D.P.U. 96-50 (Phase I) at 100-101 (December 2, 1996). The Company claims that the Department should allow it to recover the full amount of these amortizations. Co. IBr. at 32-33.

The Company's interpretation of Department precedent is erroneous. The Department allows amortization of intangible plant on an asset-specific basis, not as mass plant. These nine software packages themselves are not recurring, and will be fully amortized by July 1, 2004. The Department should not include the full amortization amount in the cast-off rates because it will not reflect a representative level of rate recovery for every year of any PBR. *WMECo,* D.P.U. 87-260 at 75 (1988).[18] The Department should remove the additional $266,000 from the Company's pro forma amortization expense.

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[18] In *WMECo,* the Company attempted to use a test year level of expense that included leases that would expire in the year following the year of the Department's order. The Department excluded the amount of these leases because they were not representative of the level of expense the Company would incur in the future. *WMECo*, D.P.U. 87-260 at 75 (1988).

B. The Department Should Require the Company to Continue Reflecting its Investment Tax Credit Amortization.

The Company claims that its removal from rate base of test year unamortized investment tax credits ("ITCs") is proper because it "believes" that it is an Option 1 company. Co. IBr. at 76. This lack of certainty on the part of the Company is understandable, given that the Company's only testimony on this matter was that, because it could not locate a copy of the investment tax credit election made by Boston Gas, Boston Gas must be an Option 1 company. Tr. 25 at 3512-3517. The uncontroverted evidence, however, shows that the Department has treated Boston Gas as an Option 2 company for at least its last three rate cases. Tr. 25 at 3513-3516. The Company has offered no reason why the Department should modify that treatment in this case.

The Company also states that if the Department were to agree with the Attorney General's position on this issue, the rate base deduction for the year-end balance of unamortized ITC should be eliminated. Co. IBr. at 76. The Department should follow the Attorney General's recommendation and reduce income tax by $842,000. If the Department does so, then it should also eliminate the rate base deduction of $1.7 million.

C. The Department Should Reduce the Company's Pro Forma Pension Expense Because it Is Unreasonable and Abnormal.

The Company denies that contributions to the pension fund in 2001 and 2002 included a catch-up for zero funding in earlier years. Co. IBr. at 78.

The magnitude of the contributions in 2001 and 2002 was affected, however, by the fact that there were no contributions in 1998, 1999, and 2000. Logically, if the contributions in 1998, 1999, and 2000 had been greater than zero, then the unfunded liability as of 2001 and 2002 would have been less, and the necessary contributions in those years to resolve, or to begin to resolve, that unfunded liability would have been less. This is true regardless of the reason for the zero contributions in the earlier years.

The Company urges the Department to reject Mr. Effron's estimate of the SFAS 87 pension cost for 2003, primarily because, in calculating the interest component of the periodic pension cost, he used a discount rate of 6.86%, reflecting a semi-annual compounding of the Company's assumed discount rate of 6.75%. Co. IBr. at 78-79. Mr. Effron explained that the use of a discount rate of 6.86% rather than 6.75% did not have a material effect on his calculation of the SFAS 87 pension expense. Tr. 20 at 2665. He testified that the effect was approximately $200,000 out of a total pension cost of $12,581,000. Tr. 20 at 2666. Other than this minor point, the Company offered no substantive criticism of Mr. Effron's calculation of the SFAS 87 pension expense.

The Department should adopt the pro forma pension expense of $10,581,000 proposed by Mr. Effron, based on the five-year average of actual cash contributions; it is adequate to cover any reasonable estimate of the Company's SFAS 87 expense in 2003.[19]

[19] It should be noted that KeySpan has told its investors that it has no plans to make any contributions to its employee retirement trust funds for the year 2003 as a result of the return it has received from the stock market. Exh. AG-1-2, KeySpan 2002 SEC 10-K, p. 60.

D. THE DEPARTMENT SHOULD REJECT THE PROPOSED PENSION RECONCILIATION MECHANISM.

The Company argues that "approval of the Company's pension mechanism will only maintain the "*status quo.*" Co. IBr. at 194.

The Company's argument is neither logical nor persuasive. If there is not presently a pension reconciliation mechanism in place, then obviously prospective implementation of such a mechanism will alter "the *status quo*." Implementation of a pension reconciliation mechanism will be a change - one that, significantly, has the effect of shifting risk from investors to ratepayers. The Company admits that the "Company's earnings and equity are protected from the volatile swings in financial markets" by the implementation of a pension reconciliation mechanism. Co. IBr. at 198. Accordingly, if the Department does approve the reconciliation mechanism, it should also recognize the reduction to the cost of equity from these new "protections" in determining the Company's authorized rate of return.

Although the Company argues that certain companies in Mr. Moul's barometer group have pension adjustment mechanisms, the fact is that less than half do. More important, however, if the Department were to find that the cost of common equity was 10.5% for Boston Gas Company, like the other distribution companies in the Commonwealth, then allowing the pension/PBOPs adjustment mechanism must necessarily reduce the Company's cost of equity below that amount, to say 10%, regardless of the Department's findings regarding the barometer group.

The Company argues that the Department should approve carrying charges on the prepaid pension costs as an element of the reconciliation mechanism because the Department has, in the past, allowed carrying charges on deferred pension or PBOP expenses. Co. IBr. at 198-201. The prepaid pension cost is different from the deferred pension expense on which the Department has allowed carrying costs: the prepaid pensions represent the difference between cash contributions to the pension plan and the periodic pension cost pursuant to SFAS 87; the deferred pension or PBOP expense on which the Department has allowed a return is the difference between cash contributions and the amounts recovered in rates. The Company has failed to cite any precedent for allowing a return on prepaid pension expense or the inclusion of prepaid pensions in rate base. The Company should not be able to recover through a reconciliation mechanism that which it cannot recover in base rates. If the Department does approve the requested reconciliation mechanism, it should not include a return on prepaid pension balances in such a mechanism.

Finally, KeySpan has told its investors that it has no plans to make any contributions to its employee retirement trust funds for the year 2003 as a result of the return it has received from the stock market. Exh. AG-1-2, KeySpan 2002 SEC 10-K, p. 60. The Department should not allow the Company's shareholders to collect cash from its customers through rates without requiring that the Company actually pay those dollars into the trust funds.

E. THE DEPARTMENT SHOULD EXCLUDE SALES PROMOTION EXPENSES FROM THE COST OF SERVICE.

The Company argues that the Department should include $11.5 million in sales promotional expenses in the cost of service. The Company claims that its combined analysis of plant additions and direct sales promotion expense satisfies the Department's requirement for a cost-benefit analysis of the sales promotion expense showing net benefits to ratepayers. Co. IBr.

at 83-85. The Company claims that the sales and growth plant additions are linked. Co. IBr. at 90.

The Company's arguments cannot avoid one crucial, inescapable fact -- the Company failed to perform a separate cost-benefit analysis for marketing program expenses that shows a net benefit to ratepayers. The Department has rejected cost benefit analyses that merely provide total costs and expected margins. *Berkshire Gas Company*, D.T.E. 01-56 at 67; *Berkshire Gas Company*, D.T.E. 01-56A at 16-17. The Company combined part of its sales promotion program expense with its growth plant additions before calculating an internal rate of return, rather than holding the sales promotion program up to scrutiny on its own. The Department should not accept this combined, clouded analysis, that fails to show whether ratepayers actually benefitted from the expense, and should remove all sales promotion expenses from the cost of service.

The record does not contain evidence supporting the Company's claim that the sales promotion program and growth plant additions are linked. Co. IBr. at 90. There is no proof that the customers who installed new gas lines in 2002 would not have done so even without the sales promotion program. The Company admits that it has not conducted a study that might show such a link. Exh. MOC 2-9. The Company has not shown that its growth additions are necessarily linked to the millions of dollars that the Company spent on boiler and furnace equipment, overhead, and installers' trips to San Francisco. RR-DTE-111.[20] Furthermore, the Company's claim that customers benefit from the promotion expense during the PBR plan is wrong. Customers will upfront more than $70 million to the Company ($11.5 million x 6 years), during

[20] The Company spent a total of $500,000 in 2002 to send the installer participants in its incentive program to San Francisco. RR-DTE-111. The holding company allocated $75,000 of that cost to the Company as "trade relations." *Id.*

the PBR period without seeing a dime of benefit, until the rate plan is over and the Company puts new rates into effect. Thus, all of the Company's net present value analyses are incorrect in showing benefits to ratepayers when in fact, all of those benefits flow to shareholders during the first six years.

Customer service quality tends to degrade when new demand overwhelms existing customer services, such as call centers and billing systems. The Legislature has acted to prevent gas companies from reducing staffing and adversely affect service quality. G.L. c. 164, § 1E (b). The record does not show the extent to which the Company's increased load will place additional burdens on its billing systems and call centers, and the level to which the Company's customer service quality will fall. This is part of the cost of adding customers on the system that the Company should have analyzed. The Company, however, states that these costs are fixed and will not rise despite increased demand. Co. IBr. at 86. The Company's stance evinces a willingness to sacrifice service quality for new load, which is not in the ratepayers' interest. The Department should reject the Company's analysis as inconsistent with the Department's goals for service quality.

The Company also has not shown that it included all appropriate costs in calculating its internal rate of return. The Company claims that $6,228,542 is the correct amount of sales costs associated with direct sales promotion activities for the IRR calculation. Co. IBr. at 84. The Company, however, has changed the amount of its test year sales promotion costs throughout this investigation. In Exh. DTE-4-27, the Company said its promotional costs were $5.9 million, while in Exh. AG-23-1, the amount changed to $7,428,258 for direct costs and $4,118,749 for indirect costs. The Company once claimed that the total amount expended on the Company's free equipment giveaway program was $6,183,540 (Exh. MOC 1-14), and also contended that the total Company incentive program (direct sales expenses) was $6,228,542 (Exh. DTE-4-28(a)). When asked to itemize the DTE Account 912 Activity 3272 expense for the free equipment giveaway program for 2002, the Company produced documents that total $11,504,843.93 and do not include any indirect costs. RR-AG-86.[21] Thus, the Company's direct costs for the sales promotion program range from $5.9 million to $11.5 million and indirect costs for administrative and general overhead add another $5.3 million. Co. IBr. at 84. The Company should have included all direct and indirect costs associated with the sales promotion program when conducting its cost-benefit analysis. The record shows that the Company should have used $11.5 million for the direct costs and $5.3 million as indirect costs, totaling $16.8 million, for the cost-benefit analysis, substantially reducing the IRR.[22]

If, despite the Company's failure to carry its burden of proof, the Department is inclined to allow some sales promotion expenses in the cost of service, the Company has not shown that its test year sales expenses are representative of the level of costs that it will incur during the period that the rates will be in effect. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51 at 39. The Company's test year sales promotional costs skyrocketed past the amount of those

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[21] RR-AG-86, pp. 12, 128, 380, 394, 477, 766, 1036, 1043. Contrast this amount with the Company's assertion that it paid equipment distributors $12,064,074 in 2002. RR MOC-1.

[22] The Company included data in its brief regarding the IRR net present value calculation that does not appear in the record. Co. IBr. at 86, n. 38. The Department does not allow parties to testify in a brief to factual matters not supported on the record. *Verizon Alternative Regulatory Plan*, D.T.E. 01-31 Phase II, Hearing Officer ruling granting motion of Attorney General to strike portions of AT&T's brief (December 19, 2002); *WMECo*, D.P.U. 86-8C-1, p. 23, n. 5 (1986); *AT&T,* D.P.U. 85-137, p. 49 (1985); *AT&T*, D.P.U. 91-79, pp. 5-11 (1991). In the absence of adequate record citations, the Department should strike footnote 38 of the Company's initial brief. because it contains assertions not supported on the record.

same costs in previous years. The annual amount of sales promotion expenses (including advertising) recovered through rates since the last rate case is $3,632,931. Exh. MOC-1-1. The Company maintained that level from 1996 through 1999, then dramatically increased its sales expense to $8.2 million in 2000 and $9.3 million in 2001. In 2002, the Company raised its sales and advertising expense to $13.6 million, a 46% increase over the previous year. *Id.* This dramatic increase in sales expense demonstrates that the test year is not representative and that the amount recovered through rates must be an average amount. The Department should use a five-year average of these costs (sales promotion and advertising combined) to reach a more reasonable and historical level of expense of $7,691,288.[23]

The Department also should reduce the recoverable amount for sales promotion and advertising expenses to reflect the additional load from electric conversions. The Company admits that 1,034 customers converted from electricity to gas during the test year. Co. IBr. at 92. This reflects 8.2% of the total number of conversions for 2002. AG IBr. at 52, n. 37. The Company claims that these conversion customers were not eligible for the free equipment program, yet the record does not show that those customers were not induced or persuaded to convert by the Company's radio, tv and newspaper advertisements (Exh. AG-20-1 and Exh. AG-25-1), the VPI installer incentives and other sales promotion expenses that the Company paid as part of its free equipment giveaway program (Exh. AG-23-1).[24] The Department should remove

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[23] This average is calculated as follows: ($3,632,931 [1998] + 3,637,441 [1999] +8,226,839 [2000] + 9,291,716 [2001] + 13,667,512 [2002] = 38,456,439) ÷ 5 = $7,691,288.

[24] Several of these advertisements refer to a free equipment offer but do not clearly and conspicuously state that electric customers are not eligible for the offer. *See, e.g.*, Exh. AG-2, AG-5, AG-7, AG-8, AG-9, AG-10, AG-11. *See also*, generally, Exh. AG 1-73(b); 940 C.M.R. §§3.01, 3.02.

$1,120,736 from the total sales promotion and advertising expense to reflect that percentage of electric conversions.[25]

F. THE DEPARTMENT SHOULD REMOVE AN ADDITIONAL $670,000 IN ADVERTISING EXPENSES FROM THE COST OF SERVICE.

The Company denies that it miscategorized advertisements and claims it is entitled to recover most of the $670,000 that the Attorney General seeks to exclude. Co. IBr. at 99-102.

1. <u>Unused Radio Advertisement.</u>

The Company agrees that its advertisement expense should be reduced to reflect the $3,000 development costs of a radio advertisement that never aired, but not the remaining $90,000 on the same invoices that the Company claims relates to another advertisement. Co. IBr. at 100.

The Company's invoices are insufficient to document the purpose of the expense. Exh. AG 25-1(4), (5), (6). They show only that the Company paid the advertisement agencies to develop a marketing campaign, and that they are related to four advertisements, one of which (Value Snobs) did not run. Contrary to the Company's assertion, the record does not show that the invoices reflect only airtime.[26] The Company has not met its burden with such limited

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[25] This amount is calculated as follows: $13,667,512 x 8.2% = $1,120,736.

[26] The Company is attempting to testify on brief as to the amount of the invoice which relates to airtime. The Department does not allow parties to testify on brief to factual matters not supported on the record. *WMECo*, D.P.U. 86-8C-1, p. 23, n.5 (1986); *AT&T*, D.P.U. 85-137, p. 49 (1985); *AT&T*, D.P.U. 91-79, pp. 5-11 (1991); *Verizon Alternative Regulatory Plan*, D.T.E. 01-31-Phase II, Hearing Officer Ruling Granting Motion Of Attorney General To Strike Portions Of AT&T's Brief, December 19, 2002. In the absence of any supporting citation to the record, the Department should strike the portion of the Company's initial brief (page 100, last full paragraph) where the Company makes this claim.

evidence, and the Department should remove $92,663 for advertisement expenses associated with the radio advertisement.

2. Illegible advertisements

The Company admits that the Department should remove approximately $9,000 for 14 missing or illegible advertisements, but argues that it is entitled to recover approximately $39,000 for four other advertisement invoices that it claims are not missing or illegible. Co. IBr. at 101. Whether the advertisements are legible and sufficient to carry the Company's burden on this issue is a factual determination for the Department. One of the four, Exh. AG 20-1(36), an invoice for a press kit that includes blacked-out pictures, typifies the difficulty parties and the Department face in reviewing obscured and illegible advertisements and invoices. The Department should exclude from the cost of service the entire $48,000 expense for illegible advertisements.

3. Conversion and Promotion advertisements

The Company argues that it should recover $230,000 on 35 invoices for advertisements that encourage customers to choose natural gas over electricity, and $173,000 on seven advertisement invoices that reflect donations, renovation projects, and business cards. Co. IBr. at 101-102.

Even a cursory review of the 35 conversion advertisements shows that the Company's assertion is factually incorrect. The seven promotion advertisements do not clearly refer only to unregulated industries; they also urge customers to use one regulated industry over another, for which the Department, applying the law, does not allow recovery. G.L. c. 164, §33A. Exhibits AG-39 and AG-40 show that consumers can use electricity to heat their pools and light their stoves, so the Department should not allow rate recovery for the Company's pool, fireplace, and stove advertisement expenses. The Company also did not show that advertisement expense for self-promotion, such as the Old North Church description and a bean burrito recipe, will benefit ratepayers. Exhs. AG 25-1 (63), (112). The Department should remove these expenses from the cost of service.

G. THE DEPARTMENT SHOULD EXCLUDE $1,637,000 IN INCREMENTAL LEASE EXPENSES BECAUSE THE COMPANY HAS NOT SHOWN ANY NET RATEPAYER BENEFIT.

According to the Company, there is no Department precedent either requiring it perform a cost/benefit analysis of a lease to provide workspace for its employees or supporting the exclusion of lease costs. Co. IBr. at 81. The Company also claims that the Waltham lease is cheaper than the Beacon Street and Norwood leases combined on a per square foot basis. *Id.*

The Department requires companies to support every challenged element of its cost of service by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion." G.L. c. 30A, § 1(6); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, at 7, n.5 (2001). When a company seeks to triple its overall office lease costs and recover an additional $1.6 million each year from ratepayers, it should not be allowed to do so without presenting a cost analysis that demonstrates net benefits to ratepayers.[27] *Fitchburg Gas and Electric Light Company v. Department of Public Utilities*, 375 Mass. 571, 582-583 (1978)

[27] The Company also claims it terminated the Beacon Street lease (Co. IBr. at 80), but the lease actually continues until April 30, 2011. Exh. AG-4-28, Attachment, Second Amendment To Lease, p. 2.

(Company failed to prove its case before the Department by presenting a clear and reasonable analysis, so the Court sustained the Department's findings against Company).

The Company's per-square foot analysis is misleading and inappropriate where, as here, the Company is renting more space, and using some of the space for non-Company purposes and to house non-Company employees. AG IBr. at 48-49; RR-AG-8; Exh. DTE-2-3 (November 15, 2002 letter).[28] The Company also sublet some of its Waltham space to a non-regulated entity, the Energy Credit Union, but did not credit the sublease revenues to ratepayers.[29] Exh. DTE-2-2(c), (d); AG IBr. at 48-49. Additionally, the Company assigned a value of zero to the Year 1 cost, instead of annualizing the lease expense, which would raise the Year 1 cost to over $1.5 million for the year. Exh. KEDNE/PJM-2, Revision 2, p. 14 of 41.

The Company claims that the Waltham location is "vastly improving the efficiency of its working environment for employees." Co. IBr. at 82. While Company testimony claimed that it would be more efficient to have all employees together in Waltham (Tr. 8, pp. 910-911), no evidence supports the Company's assertion in its brief of vast efficiency gains. In fact, there is no evidence establishing any improved efficiency, measuring the amount of efficiency gained, or

[28] "Each of the undersigned Companies will receive services from personnel at the Leased Premises [52 Second Avenue, Waltham, Massachusetts] ... ." This two-page letter is contained within the bulk exhibit of Exh. DTE-2-3 but is otherwise unnumbered. The letter is signed by Nicolas Stavropoulos in his capacities as President and C.O.O. of Boston Gas Company, Colonial Gas Company, Essex Gas Company, and EnergyNorth Natural Gas, Inc.

[29] The Company sublet 2,029 square feet of its Waltham space to a non-regulated, unaffiliated entity, the Energy Credit Union, at the Company's rental rate. Exh. DTE 2-2(c), (d); Exh. DTE 2-3. The Company did not reflect its sublease revenue as an offset to its annualized lease expense. Based on a ratio of square footage (2,029/113,000) times the annualized Waltham lease expense ($1,560,619), the Company should reduce its lease expense by $28,022 to offset the Energy Credit Union sublease rental. Exh. DTE 2-2 Exh.; DTE 2-3; Exh. KEDNE/PJM-2, Revision 2, p. 14 of 41. The Department should reduce the Company's lease expense by this known and measurable offset.

relating any increased efficiencies to cost containment or ratepayer benefits, which are the Department's standards for rate inclusion.[30] The Company's claim is therefore unsupported and the Department should disallow the incremental lease expense, $1,637,000, from the cost of service.

H. The Department Should Exclude Any Proposed Merit, Incentive and Other Wage Increases for Non-union Employees.

The Company argues that the Department should allow its proposed merit, incentive and other wage increases for non-union employees because its wage levels and the percentage and amounts of the proposed increases are reasonable. Co. IBr. at 105-117.

The Department examines the reasonableness of the percentage or amount of an increase, however, in the context of current levels of **total** compensation. *Massachusetts Electric Company*, D.P.U. 95-40 at 26; *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 90. The Company has presented no persuasive response to the fact that its average total compensation per employee already exceeds the local gas industry average.[31] The Company fails to justify why it should raise its non-union employee compensation even further above, and out of line from, the average non-union compensation of other New England gas utility employees. *See Berkshire Gas Company*, D.T.E. 01-56 at 54 (2002)(increases allowed when commensurate

[30] In fact, the Company has become less efficient as discussed *supra*, in section IV.

[31] The Company claims that it was correct to include electric companies in its comparison since it competes for those same skilled workers. Electric and gas workers are not all interchangeable, however. The total compensation per employee is so much higher for electric companies in New England that including electric workers skews the result. Exh. KEDNE/JCO-12. The Company has failed to show that the most appropriate comparison group in this case is not the other gas utilities in the area.

with salaries and wages of similar utility employees of other companies). Adding any non-union merit, incentive or other wage increases to total compensation levels that already exceed the local gas industry average is unreasonable and inappropriate when total customer bills have been rising rapidly and are expected to remain at very high levels.

The Company argues that its non-union wage disparity compared to other local gas utility employees is justified because its employees are more efficient, offsetting its higher employee compensation costs. Co. IBr. at 115. The Company has not proved, however, that its employees are more efficient than other local utility employees or that the Company's operations are sufficiently efficient to offset any higher employee compensation costs.[32] To the contrary, there is record evidence indicating otherwise. Exh. AG-41; RR-DTE-76.

The Company disputes the Attorney General's claim that the Company's comparative analysis data is flawed in its method and calculations. It states that it provided several other studies and data, such as Exhibits KEDNE/JCO-9 and KEDNE/JCO-10, and claims that the Attorney General ignores all of the Company's studies and focuses on a labeling error.[33] Co. IBr., pp 113-114. The Company does not show, however, that its methods and its data are correct.[34] These studies, moreover, do not address the fact that the Company's total compensation per employee is greater than the local industry average: Exhibit KEDNE/JCO-9

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[32] Even if the Company's operations were more efficient than its peers, that efficiency would not necessarily be attributable primarily to labor. Other factors such as capital substitution, economies of scale, new technology and even lower taxes could cause an apparent efficiency. Exh. AG-41.

[33] While the Company's confusion between the average and median was for union, not non-union compensation. The number of errors in this case casts doubt on the reliability of the Company's analyses.

[34] The Company's argument that only union employees receive certain benefits is contradicted by the testimony of its witnesses. Co. IBr. at 116; Tr. 17 at 2238-2239; Tr. 16 at 2108-2119.

simply compares base pay and does not compare **total** compensation, including benefits, Tr. 16 at 2133-2137; Exhibit KEDNE/JCO-10 shows only 2003 projected, not actual, percentage increases that, if granted, would compound the excessive total compensation.

For these reasons, the Department should exclude from the cost of service the proposed merit, incentive or other non-union wage increases.

I. THE DEPARTMENT SHOULD EXCLUDE NUCLEAR INSURANCE PREMIUMS ALLOCATED FROM KEYSPAN.

The Company claims that no change is needed to its proposed post-test year insurance expense adjustment of $607,287. Co. IBr. at 57-58. On August 21, 2003, however, the Company agreed to remove from the cost of service the portion of KeySpan's nuclear power liability premium expense that the holding company allocated to Boston Gas:[35]

> Although KeySpan does not own or operate any Nuclear Power Plants, the Long Island Lighting Company (LILCO), a predecessor company of KeySpan, built but never operated a nuclear power plant. The Nuclear Liability Insurance is for any claims that may result from radioactivity due to the testing of the Shoreham Nuclear Power Plant. Expense of $9,694 was inadvertently included [in] the Company's cost of service and should be eliminated.

RR-DTE-110; Tr. 25, pp. 3428-3429. The Department should remove $10,000 from the cost of service for this improper insurance expense allocation.

[35] KeySpan allocated to Boston Gas 12.80% ($9,694) of the $75,738 Marsh USA - American Nuclear property insurance premium. Exh. KEDNE/PJM-4; Exh. KEDNE/PJM-2, Revision 2, page 13 of 41, line 13.

J. THE DEPARTMENT SHOULD REMOVE ADDITIONAL DIG SAFE FINES.

The Company claims that its $71,000 adjustment removing test year fines is not in dispute. Co. IBr. at 50, 62. The Company did not address, however, the additional $51,000 in Dig Safe fines discussed in the Attorney General's brief. AG IBr. at 59-60. The Department should exclude from the cost of service all fines paid by the Company, including the Dig Safe ones, for a total adjustment of $122,000.

IX. COST OF CAPITAL

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED CAPITAL STRUCTURE AND ARTIFICIAL DEBT RATIO

The Department must determine whether a hypothetical capital structure is appropriate, in this case, and, if so, what debt and equity ratios it should order for an efficient cost of capital. The Company argues that any debt from the holding company must be associated with the merger and, therefore, must be eliminated from the capital structure in its totality. Co.IBr. at 128-129.

The Company claims that its proposed 50 percent equity ratio is cost efficient, relying on Mr. Moul's testimony. Co.IBr., pp, 125-126.

The evidence, however, proves otherwise. Where both Boston Gas Company and KeySpan have debt ratios near 59 percent and where they both have "A" ratings from the bond ratings agencies, it is clear that the Company, ***as well as the marketplace***, have decided that a 59 percent debt ratio provides for reasonable and cost efficient capital structure. Exh. KEDNE/PRM-1 at 18; Exh. AG-1-16. The Department should recognize this reality and not load up the capital structure with equity, making an inefficient, costly capital structure. The Department should reject the Company's proposed capital structure ratios and instead use the Company's actual 59.4 percent debt, 0.96 percent preferred equity, and 39.65 percent common equity ratios.

B. THE DEPARTMENT SHOULD ADOPT A COST OF COMMON EQUITY OF 8.99% OVERALL, AND LOWER FOR RESIDENTIAL CUSTOMERS

The Attorney General recommended a 8.99 percent allowed rate of return on common equity as being a reasonable and fair overall return for shareholders. AG IBr. at 81-85. The Company argues for a 12.18% allowed return, relying on Mr. Moul's testimony and recommendations. Mr. Moul's methodologies are, however, fatally flawed and his recommendations are over-inflated.[36] The Attorney General will address only the most problematic of the Company's arguments here.

1. Boston Gas Company Is Less Risky Than The Comparison Group

The Company argues that the investment risk in Boston Gas Company's gas distribution services is comparable to Mr. Moul's barometer group of companies, except for one important aspect, its more variable earned returns, which it claims make the Company more risky than the barometer group. Co.IBr. at 131-132. Mr. Moul's analysis of the variability of the earned

[36] The Company argues that Mr. Moul's recommendation is conservative, since it makes no provision for the prospect that the Company may not achieve the rate of return because of "unforeseen events" that might occur during the effective period of the PBR plan. Co.IBr. at 130-131. However, there are many provisions in the proposed PBR plan that protect the Company from "unforeseen events" such as (1) an exogenous factor that provides recovery of unexpected changes in costs "outside the Company's control" that is unique to gas distribution companies; (2) an inflation factor that directly compensates the Company for any changes in inflation, whether small or large; and, ultimately, (3) an earnings sharing mechanism that limits the Company's downside earnings.

returns, however, is flawed here as it has been every time he has presented his comparable group analysis.

The statistics that Mr. Moul calculates for his barometer group for comparison to Boston Gas Company are all determined by averaging the individual statistics for each of the companies in the group. See Exh. KEDNE/PRM-2, p. 4. Mr. Moul determines the variability of the earned returns on common equity for his barometer group ***after*** he averages those returns together. Of course, as in any group analysis, using the average numbers will reduce their variability. The correct analysis would have been to determine the variability of the earned returns for each one of the companies in the barometer group individually, and then average together those individual measures of variability. If Mr. Moul had used this correct method, he would have found that the variability of the earned returns was significantly higher for the barometer group, indicating more investment risk.

The other evidence in the record also indicates the higher risk for the barometer group. *See*, *e.g., Value Line Investment Survey*s, Exh. AG-14-19. Value Line's explicit analysis of and concerns about the non-utility businesses that each of the companies in Mr. Moul's barometer group operates indicate the high risk associated with those investments. *Id*. For instance, AGL Resources owns and operates both an energy trading business and a natural gas marketing business that account for more than 13 percent of its business. *Id.* Atmos Energy also has a marketing business, along with investments in electric generation. *Id.* New Jersey Resources has large investments in unregulated energy services and gas storage. *Id.* NICOR also has an energy trading business. *Id.* Peoples Energy, on the other hand, has both energy trading businesses and oil and gas exploration businesses. *Id*. Piedmont brokers natural gas as well as gas equipment.

Id. South Jersey Industries' non-utility business, which includes gas marketing and electric generation, makes up more than 20 percent of its business. *Id.* WGL also markets gas and other energy services. *Id.*

Mr. Moul failed to adjust his recommended cost of common equity to recognize these very significant concerns and higher risks associated with the companies in his comparison group. As a result, any results of the cost of capital for his barometer group reflect a higher investment risk when compared to the stand-alone risk of a gas distribution company like Boston Gas Company.

2. A Four Percent Growth Rate Is A Reasonable Discounted Cash Flow Growth Rate

Mr. Moul's Discounted Cash Flow ("DCF") analysis and his recommendation of a six percent DCF growth rate are incorrect; his methodologies and analyses have systematically over-inflated the growth rate estimate.[37] AG IBr. at 82-84. The Attorney General recommends that the Department use a four percent growth rate in the DCF analysis. The Company argues that (1) there is no evidence to support a four percent DCF growth rate for the barometer group, (2) the investment analyst's forecasts for the barometer group are the only valid DCF growth rate estimates, and (3) the long-run forecast growth rate in U.S. corporate profits is the best indicator of the long-run growth rate in dividends paid per share for a gas distribution company. Each of those arguments is incorrect.

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[37] In *Boston Gas Company*, D.P.U. 96-50, Mr. Moul estimated a DCF growth rate of 5.5 percent based on earnings forecasts, yet all of the Company's actual growth rates since then have been at least 100 basis points below that. Exh. KEDNE/PRM-2 at 10 and Exh. AG-14-20.

The evidence in this case and in the Company's last case, clearly indicates that a four percent DCF growth rate is actually near the upper end of the Company's actual growth rates and the growth rates the Company can expect to achieve. *See* AG IBr. at 83, *citing* Exh. KEDNE/PRM-2, p. 10 and Exh. AG -14-20. All of the near-term and long-term historical growth rates have been below four percent except for the ten-year earnings per share of 4.44 percent. *Id*. Neither the Company nor Mr. Moul could provide any evidence to explain what change in the underlying growth in revenues or decrease in costs might cause such an increase in these historical growth rates, much less fulfill Mr. Moul's overly optimistic forecasts.[38]

Finally, the Company's claim that the long-run forecast growth rate in corporate profits is the best estimate of the long-run growth rate for the gas distribution companies in the barometer group simply falls under its own weight. The corporate profits for the companies in the U.S. economy would include all of those in the unregulated world, including the high growth industries such as computers, software, biotech and pharmacy. As Mr. Moul has recognized, the risks and expected returns for those other industries are not comparable to those of the regulated gas distribution industry.

3. The Most Recent Six Months Of Available Dividend Yields Is The Appropriate Data To Use In The DCF Analysis

The Attorney General, in his initial brief, recommended that the Department use the most recent six months of information available to determine the DCF dividend yield. AG IBr. at. 82. The Company argues that using the most recent six months of information to determine the DCF dividend yield is somehow inconsistent with the period that the Attorney General used to

[38] Mr. Moul relies solely on forecasts from sell side investment analysts, which, by their nature, over-estimate the growth rates of the companies in the barometer group.

"establish the risk-free rate of return." Co.IBr. at 139. The Attorney General did not use the "risk-free rate of return" in his recommendation of a DCF cost of common equity. The Company's argument is simply misplaced and should be ignored by the Department.[39]

4. Residential Classes' Cost of Equity

The Company criticizes the Attorney General's recommendation that the Department require the Company to set the cost of common equity for the residential classes at a rate that is 100 basis points lower than that for the commercial and industrial classes. Co. IBr. at 150. The Company's criticism is contrary to its own witnesses' testimony. The Company claims there is insufficient evidence to support the Attorney General's position, even though two different Company witnesses testified that residential customers are less risky than commercial and industrial customers. AG IBr. at 92-93. The Company also claims that there is no precedential support for establishing different costs of equity in setting class revenue requirements. Co. IBr. at 150. The Company is incorrect again. The Department has previously recognized differences in risk between classes.

> ... to the extent that there are statistically verifiable differences in the risk of sales of electricity to the various rate classes, fairness and cost causation principles would appear to justify the identification and evaluation of those differences, including the quantification of their corresponding costs.

Massachusetts Electric Company, D.P.U. 95-40 at 115-116 (1995).

The Department is committed to assigning costs based on causation. *Id.*; *Boston Gas Company*, D.P.U. 93-60, pp. 331-332 (1993); *Western Massachusetts Electric Company*, D.P.U.

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[39] The Attorney General did use what have been called "risk-free" rates of return in his arguments regarding Mr. Moul Capital Asset Pricing Model ("CAPM"). Ag IBr. at 88-89. However, those rates did not affect, nor should they enter into, the DCF analysis.

90-300, p. 13 (1991); *Boston Edison Company*, D.P.U. 1720, at 112-120 (1984); *Mass.-American Water Company*, D.P.U. 95-118, p. 162 (1996); *Interruptible Transportation*, D.P.U. 93-141-A, p. 63 (1996). Higher investment risk increases the cost of equity to the firm. Exh. KDNE/PRM-1 at 46-50 and Appendix H. The record in this case indicates that the risk associated with residential customers is lower than that of commercial and industrial customers and has been quantified. Tr. 7 at 813-815. The Department should acknowledge the value residential classes bring to the Company's customer mix and the lower cost of common equity that should result.

The Department, spurred by the Natural Gas Policy Act (1978) and the desire of large commercial industrial customers, began the transition to competition more than a decade ago. *See Gas Transportation*, D.P.U. 85-178. First, commercial and industrial rates were unbundled, fostering competition for this select group and allowing them to benefit in the form of substantial savings in gas commodity costs beginning in the late 1980s. At the same time, the Department established liberal contracting and pricing standards for interruptible customers (all of whom are commercial and industrial customers) and allowed special contracts for this same commercial/industrial class to go into effect with price floors set at marginal costs. *Interruptible Transportation*, D.P.U. 93-141-A, p. 10. Almost a decade after benefits began to flow to large commercial and industrial customers, competition was opened to all customers with the unbundling of all tariffed rates. This, too, was done for the benefit of consumers:

> ...[t]he Department determined that the benefits of competition should be extended to all customers including the residential customers. The Department's ultimate objective throughout its unbundling efforts has been to provide the opportunity for the residential and smaller commercial

> and industrial users of natural gas to benefit from the prospective benefits of lower commodity prices...

April 21, 2000, Department of Telecommunications and Energy Report to the Joint Committee on Government Regulations on the Work of the Massachusetts Gas Unbundling Collaborative July 1997 to May 2000, p. 2.

Benefits from competition have not been evenly distributed among classes. The residential class has no choice. The residential classes have no special contract, quasi-firm or interruptible contract or other special pricing options available to them. *Bay State Gas Company*, D.T.E. 01-81 at 27-28 (2002) (finding competition benefits for commercial and industrial customers not available to residential customers). The Department should recognize in rates, however, the significant benefits that are unique to the residential classes--they are a stable, predictable load that generates 70% of the Company's base revenues. Exh. KEDNE/AEL-5. The Department should implement the 100 basis points lower return on equity for the residential class in determining the class revenue requirements in this case.

C. SUMMARY AND RECOMMENDATIONS

For all of the reasons discussed above, the Department should set an 8.99 percent allowed return on common equity to determine the Company's overall cost of capital. AG IBr. at 82-85. The Department also should differentiate the costs of common equity for the residential and other classes by providing a one hundred basis point difference in their rates of return.

X. RATE DESIGN

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED WEATHER STABILIZATION CLAUSE.

The Company dismisses as no longer relevant Department precedents on Weather Stabilization Clause ("WSC")[40] issues from the early 1990's. Co. IBr. at 205-206; *Bay State Gas Company*, D.P.U. 92-111 (1992); *Berkshire Gas Company*, D.P.U. 92-210 (1993). The Company implies that the Department's only concern with WSCs in those cases was weather volatility, and now the availability of hedging instruments reduces that concern. *Id*.

A decade ago, the Department rejected WSCs, expressing several concerns, not just about weather volatility, that remain relevant today. The Department should reject the Company's proposed WSC because it is not an appropriate mechanism to benefit its customers. The Company claims that the proposed WSC would benefit customers, and increased customer satisfaction would be the only benefit to the Company. Co. IBr. at 205. The Company would benefit from the WSC, however, because it would no longer need to enter into financial arrangements in order to remove the risk of weather volatility as it does today. Tr. 21 at 2884-2885. If the Department approves the WSC, then customers would assume all the risk of weather volatility. The Company would realize the revenue stabilizing benefit without having to incur the expense of financial arrangements. Far more than customer satisfaction, the Company

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[40] The Company refers to its proposal as a Weather Normalization Clause ("WNC"). Since the Department preferred the proposal be called Weather Stabilization Clause to avoid confusion (Tr. 4, p. 407), that is how the Attorney General will refer to it.

could receive a $14.5 million benefit aggregated from the many small changes to individual bills while an average residential heating customer's annual benefit would be $3. See RR-DTE-5.[41]

The Department, when evaluating past WSC proposals, expressed concern with the reliability and accuracy of companies' weather data. *Bay State*, D.P.U. 92-111, pp. 57-61, *Berkshire Gas Company*, D.P.U. 92-210, pp. 191-199. The Company adopted a new methodology[42] for calculating daily degree days as a result of the conversion to the CRIS billing system. RR-DTE-19 [Revised] and Exh. DTE-2-40 (rev. 2). In the CRIS system, the daily degree days are calculated by averaging the temperature over nine intervals in a "gas day"[43] and

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[41] As an example, based on the Weather Stabilization Adjustment ("WA") data in RR-DTE-5, an R-3 customer bill, with annual usage of 600 therms (assuming this is an average R-3 customer), would experience an approximately $3 difference in the year's bill [the total of adding the therm usage multiplied by WA for the months of January, February, March, April, November and December]. The Company, however, would enjoy a cash flow stabilizing adjustment of approximately $14.5 million from all classes [number of bills for R-3 = 1,900,677 (Exh. KEDNE/ALS-4(REVISED)) multiplied by $3]. The $14.5 million is the aggregated affect of applying this calculation to all classes.

[42] Evidently, the Company was unaware at the time it filed its rate case that the CRIS billing system used a completely different weather normalization process. Exh. DTE-2-40 (rev. 2) reveals that the CRIS system uses the average of 9 temperature readings during a gas day (the 24 hours beginning at 10 AM), not the average of the daily high and low temperatures. The Company also learned during these proceedings that its old billing system had been using 10 years of data to determine normal weather, not 20 years as required by the Department. Exh. AG-8-30 (rev). It is unclear from the record when the Company began incorporating the 10 year average and whether it relied on the 10 year average to develop the weather normalization adjustments in annual PBR plan rate adjustment filings. Tr. 7, pp. 750-752. Another billing system difference affecting weather normalization calculations that the Company revealed was that the CRIS system does not recognize certain codes used by the predecessor system, CSS. The CSS system used a 9.99999 code to indicate where there was insufficient customer data to determine a customer's base and heating load. CRIS does not recognize the 9.99999 as a code and processes the numerical value in calculating a customer's heating load. RR-DTE-22 (clarifying Tr. 7, p. 733). These billing system differences were not obvious to the Company's experts who worked intensely with the data in preparing key rate case revenue, cost and rate design adjustments. The Department, then, should exercise caution in approving a proposed weather stabilization clause that will incorporate very opaque calculations that rely on the integrity of the newly adopted CRIS system, which at best, has been found to have many "kinks" to be ironed out.

[43] A "gas day" is defined by the Company as a 24 hour period beginning at 10:00 A.M. RR-DTE-19 [Revised].

subtracting this average from 65; previously, the daily degree day was calculated by averaging the high and low temperature for a calendar day - 12:00 A.M. to 12:00 P.M. *Id.* As a result of this change, there is a difference in the monthly normal and actual billed degree day calculations. Compare RR-DTE-19 Attachment Original and Revised.[44] The Company has not shown that the new methodology will not inappropriately distort the WSC's weather stabilization adjustment calculation. The Department would have difficulty revealing this distortion in any type of audit.

The Company also dismisses as no longer relevant whether the WSC would require an adjustment to the rate of return on common equity, since the companies in Mr. Moul's barometer group have weather adjustments. Co. IBr. at 206. To the contrary, this issue is highly relevant. The Department has never set an ROE on a company that has a WSC. Reducing the Company's risk of revenue volatility due to weather could significantly reduce its cost of capital, below that of companies that do not have a weather adjustment. Thus if the Department found that the allowed return on common equity should be 10.5% like all the other distribution companies in the Commonwealth without a weather adjustment, Boston Gas Company would need a lower rate of return of say 10% with a weather adjustment. If the Department approves the WSC in this case, it should also lower the Company's allowed rate of return on common equity.

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[44] In comparing the old and new calculations for November, there are differences that are as much as 2.6 percent higher when the new calculation for Normal Billing Degree Days is used and Actual Billing Degree Days varying by as much as 5.5 percent on a billing cycle basis under the new method compared to the old. RR-DTE-19 Attachment p. 9 (Original and Revised). The impact on individual customers can be seen by comparing specific customer variances (R-3 customer 4362216450) in monthly normal and actual degree days. RR-DTE-5 (incorporating corrections); Exh. DTE-3-29 (also provided in response to DTE-10-20 and DTE-10-21.

B. THE COMPANY EXAGGERATES THE BENEFITS OF ITS RATE IMPACT MITIGATION PROPOSALS, WHICH ARE INSUFFICIENT TO PROTECT CUSTOMERS.

The Company states that it will limit the impact of any base rate increase to no more than 10 percent for the average customer in each rate class as compared to the total 2002 bill. Co. IBr. at 5. Mitigation of rate impacts is certainly needed where a company proposes one of the largest natural gas base rate increases in Massachusetts history at a time when gas costs have risen sharply.

The Company, however, has failed to provide any specific information about its rate cap proposal, so that the Department cannot evaluate its impact on customers. The Company did not file tariffs, details of the plan, or any plans for implementation until the Attorney General requested them. Exh. AG-23-23, AG-23-24 and AG-23-25. The Company's rate design witness could not provide any information about how the Company would implement the rate cap. Tr. 3, pp. 368-374. The tariffs that the Company finally filed would only cap rates for average customers' rates at a 10 percent total bill increase–it appears that the 10 percent is only to be realized if there is no increase in the CGA over the average 2002 CGA. Exh. AG-23-23 (supp.).

If the CGA is higher than the 2002 average, customers may experience much higher bill impacts than 10%. The Company has timed its filing in such a way that its base rate increase will be implemented around November 1, 2003, the same time the peak CGA rates go into effect and customers' usage increases with the colder weather.[45] The Company is proposing that in November the base rate component for an average residential heating customer increase more

[45] The Department should determine potential bill impacts based on the CGA and proposed base rate revenues and have the Company notify customers of the potential total monthly bill impacts before November 1.

than $15, which is more than 25% higher than the base rate bill for the same use in November, 2002. For the low income heating customer, the impact is even more dramatic--the base rate distribution component, the non-CGA charges, would increase by more than 28 percent ($10). This can be a significant amount for anyone trying to make ends meet on a fixed income.[46]

The Company's more effective mitigation is adjusting the rates to reflect the correction to the "cell reference error" in the rate design model. RR-AG-17. The rates the Company has filed incorporating that correction would still produce approximately the same bill impacts for the average residential heating customer (only $0.30 lower for a November bill compared with the 10 percent capped rates), but the result is more reasonable than a cap that will eventually be revoked. RR-AG-97.[47]

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[46] While expanding low income eligibility and the On Track program may help a limited number of customers, this does not address the rate impact problem created by the Company's rate request for the vast majority of the Company's customers.

[47] The Company is now proposing to use the March 2003 low income customer count to develop the low income bill determinants. RR-AG-17. The Company has not provided statistical evidence supporting its low income bill determinants. The Company has not shown why it should not use the actual test year weather normalized bill determinants for designing the low income rates and determining the low income subsidy. The Department should require an accurate representation of the actual levels of low income customer count and usage levels. The Department should order the Company to use the test year adjusted customer count and usage levels and to document how these values were calculated as part of the compliance filing. The Company may have unfairly profited from incorrect calculation of the low income discount in previous proceedings. In the Company's last rate case the low income discount was approximately $4.5 million, $.5 million greater than the corrected amount in this case. RR-AG-98 and RR-AG-97 (electronic). The low income customer numbers are significantly different--the D.P.U. 96-50 R-2 count is 10,500 and in this case the Company would use 5,100; the D.P.U. 96-50 R-4 count is 22,200 and here it is 16,000. According to a notation in the rate design spreadsheet model the March 1996 customer counts for R-2 and R-4 were 4,768 and 17,652 respectively. RR-AG-98 and RR-AG-97 (electronic), "Input" worksheet, cells D4 and D11. *See also* RR-DTE-2 (low income customers 1999 to 2002, monthly counts). These unexplained discrepancies cast doubt on all of the Company's calculations. The Department should require the Company to explain, document and support all of its computations performed by Company designed systems and models, including not only the rate design model, but also the cost of service models (embedded and marginal), and calculations performed by the billing system. The Department should require an independent audit of all these systems and models.

XI. THE PROPOSED PBR PLAN

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED PBR PLAN BECAUSE IT IS CONTRARY TO DEPARTMENT GOALS AND UNFAIR TO RATEPAYERS.

1. Summary And Standard Of Review

The Department has set forth a number of goals and standards to evaluate incentive regulation plans. *Incentive Regulation*, D.P.U. 94-158 at 57-64 (1995); *Boston Gas Company*, D.P.U. 96-50 at 242-5 (1996). A petitioner must show that its approach is more likely than cost of service ratemaking to advance the Department's traditional goals of safe, reliable, least-cost energy and promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation. *Id.* The Department has also indicated that an incentive plan should not reduce safety, reliability or existing standards of customer service, or focus excessively on cost recovery issues. A plan should provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. *Id.*

The Department should reject the Company's proposed PBR plan because it fails to meet the Department's standards and does not comport with sound regulatory and economic policy. Exh. AG-41. The Company proposes the nation's only "inflation-plus" PBR plan that would raise rather than lower rates from what they would otherwise be, while increasing Company profits. Existing standards of customer service may be affected if the Company again defers capital improvements until the end of the PBR period and improperly reduces staffing levels.[48]

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[48] The Company filed an illustrative tariff that, for the most part, reflects the procedures it followed in its annual PBR filings under the prior plan. Exh. AG-23-22. The Company proposes to exclude, however, Service Quality penalties from its PBR filings, instead making separate Service Quality filings and "payment of any financial penalties that may be incurred through the Local Distribution Adjustment Clause factor." *Id.* Under the operation of the prior PBR plan, Service Quality penalties were reflected

This PBR proposal has already raised rather than lowered administrative costs and burdens, with consultant costs that may exceed $1 million and extensive review requirements during an already overloaded suspension period. The Company has already focused excessively on cost recovery issues by loading costs into test years under a hybrid PBR approach that seeks to maximize cast-off rates, automatic inflation levels and the period of automatic increases, while improperly seeking to expand potential exogenous factor recoveries. The proposed PBR would not promote economic efficiency because it lacks adequate incentives for cost containment. The Company would be able to make ample profits even if it does not lower costs by becoming more efficient. *Id.*; RR-DTE-72; Tr. 26 at 3641.

The Attorney General has already adequately discussed, in this brief and his Initial Brief, the proposed PBR plan's inability to control costs and lower rates, the Company's excessive focus on cost recovery, and the potential impact on existing standards of customer service from deferring capital improvements until the end of the PBR period and improperly reducing staffing levels. The two issues addressed by the Company in its Initial Brief that merit an additional response are whether the PBR plan is, (1) unduly complex and unreviewable, and (2) inappropriate because it suffers from false precision and methodolgical flaws.

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in annual revenues that were the base for the PBR adjustment. By refunding penalties through the Local Distribution Adjustment Clause factor, the Company will avoid the enduring affect of the penalties that the Department deemed appropriate in the Boston Gas PBR and in the NYNEX PBR case where it explicitly addressed the issue. *Investigation by the Department of Telecommunications and Energy of Verizon New England, Inc.'s, Fifth Annual Price Cap Compliance Filing* D.T.E. 99-102, pp. 11-12 (2000). Although the Company files its Service Quality reports in March along with all other utilities, the Department should require that any penalties be reflected in rates at the time the PBR increases are proposed, and these penalties should be incorporated the base rate revenue levels to which the PBR adjustment is applied.

2. The Company's PBR plan Is Unduly Complex And Unreviewable.

The Company argues that the Pacific Economic Group ("PEG") model "…is not an unduly complex 'black box'" Co. IBr. at 185.

The Company based its plan on a number of complex analyses, including the Total Factor Productivity ("TFP") study of the Northeast, the economic cost model, and the capital cost computations that both models use. The model that supposedly proves slower productivity growth in the Northeast gas utility sample than in the economy, and the model that supposedly shows Boston Gas is an efficient utility, are both extremely complex and rely on various simplifications that may bias the results. Tr. 26 at 3627-3628; RR-DTE-76.

The Company alleges that the PBR models are not too complex to rely on because the Department reviewed analogous models in the Company's last PBR proceeding. Co.IBr. at 185-186. The record clearly indicates, however, that the results of the previous case do not provide full justification for using the PEG's results in this case. The models are different from those presented previously.[49] The definition of output is different. The database is different.[50] There is no productivity study of the entire United States for reference. The models, moreover, were explored in more depth in this proceeding than in the previous proceeding. The Company argues that "PEG's methods are grounded in the literature." Co.IBr. at 186. This literature primarily addresses very complex mathematical techniques, and does not address many of the significant problems that are extremely important when the studies are used to compare the gas industry to other industries, and to compare one gas utility to others.

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[49] "... there were a number of changes that we made to the study methodology..." Tr. 11 at 1280.

[50] The utilities analyzed are different; the data required "imputations" Exh. AG-7-12.

The Company's claim that the study was not unduly complex is belied by the complexity of the case it presented, including the testimony about the mathematical techniques used.[51] The study took an unduly long time;[52] PEG developed the basic data itself[53] and still contained some errors.[54] As late as the hearings, PEG was working on a different method of addressing taxes in the models. Tr. 10 at 1371.

The Company notes that it provided spreadsheets that included formulas to show the calculation of key variables. The spreadsheets, however, did not provide formulas for most of the variables, including such important variables as the initial adjusted value of capital cost. Tr. 18 at 2446-2447. The Company continues to maintain that all formulae were contained in these spreadsheet models, although they have not cited any record evidence that shows this.[55]

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[51] *See, e.g.,* KEDNE-LRK-2 – References, Appendix ("Tornqvist form index; "triangularized weighting"); KEDNE-LRK-3, ("augmenting the cost equation with ..equations implied by Sherpard's Lemma").

[52] Dr. Kaufman began working on these studies in March 2002.

[53] Tr. 10 at 1127, 1130; Exh. KEDNE-LRK-3, p.3.

[54] During the discovery process, PEG "corrected" several errors in data in the original study. Exh. AG-31-11. Dr. Kaufman agreed that a first year cost of $1,728 compared to a second year cost of 32,545 was "anomalous" and was due to a major structural change in the utility, but still used this data, even though he excluded utilities whose data was clouded by mergers. Tr. 11 at 1434-35).

[55] On July 2 the Company provided electronically an additional response that purported to contain "an augmented dataset that includes additional formulae…" Exh. AG 30-8. These words do not make clear whether this response actually contained any or all of the missing information; in any event, the file provided was garbled in the electronic transmission and was totally unreadable. The Attorney General notified the Company of this problem, but the Company did not provide a useable replacement prior to the date on which testimony was due. The DTE has these models and can determine whether it can use all of the spreadsheets provided to determine whether the models were accurate and reviewable.

3. The Models Contain Flaws That May Bias the Results.

Although PEG's models are complex, they also rely on simplifying assumptions that may bias the results. These simplifications include, among others, the assumptions that: (1) plant in 1983 represented the same age and the same rate of past investment among utilities across the country; (2) use of a single Handy-Whitman index for different utilities (varying only by regional differences in the Handy-Whitman index) accurately categorizes plant of similar vintages for utilities across the country, despite differences in the amount of storage, transmission mains, distribution mains, services, etc. among the utilities; and (3) new customers had the same impact on costs whether or not they required the building of new mains. Tr. 18 at 2448-2449.

The Company argues that the Attorney General failed to mention any variables excluded from the study. Co.IBr. at 192. To the contrary, Lee Smith mentioned a number of variables. Chiefly, the study did not include a variable or model treatment to measure whether it was less expensive to add new customers on existing distribution lines than on new lines. This would seem to be a fairly basic difference between utilities. The proxy for new customers on new distribution lines was significant, as suggested by the Attorney General, and had the expected sign. Exh. AG-30-6.

4. The Company Has Not Shown That Northeast Productivity Growth Is Less Than The Nation's.

In this case there is no comparison between productivity growth in the NE and the nation. RR-DTE-76. The Company seems to suggest that the DTE must accept its Northeast productivity study, because the Department "accepted a regional definition of the gas distribution industry" in D.P.U. 96-50. Dr. Kaufman refers to the "reality" that Northeast productivity growth is lower than the productivity growth in the rest of the country. Tr. 10 at 1216. Dr. Kaufman apparently bases that reality, however, on cost estimates that are themselves unreal. RR-DTE-76. The productivity studies examined in D.P.U. 96-50 were quite different from the single Northeast productivity study presented in this case.

PEG's productivity and cost studies are both flawed, partly due to fundamental data problems, particularly with regard to the capital stock. Exh. AG-41; Tr. 26 at 3631-3638; RR DTE-76. If the initial value of the capital stock was undervalued for a group of utilities, their productivity growth would appear lower than it would otherwise be. Dr. Kaufmann testified that "[a]ll else equal, this would lead to relatively greater cost increases for distributors with a more aged capital stock." Co. IBr. at 190.

The Company argues, however, that the initial value of stock is not a problem, based on its claim that the Northeast dummy variable in the cost study should be negative if the study understated capital costs of older utilities. If Northeast utilities were uniformly older than the rest of the country, the cost understatement would have a negative effect, but not necessarily produce a negative coefficient for the Northeast. Exh. AG-41; RR-DTE-76; Tr. 26 at 3634-3635. The Company argues that this conclusion is not correct "if the regression also includes other factors that would affect costs in the Northeast, such as frost depth." Co. IBr. at 191.

Frost depth is only one of the reasons why Northeast costs might be higher, and the frost depth variable was not in fact included in the equation used. The Company, moreover, is oversimplifying the world; Northeast utilities do not uniformly have plant of the same, older vintage, but rather there is a great deal of variance among them, and some utilities in the rest of the country also have older plant. Thus Northeast utilities may tend to be older, but the lack of uniformity in this characteristic is another reason why the Northeast dummy variable cannot prove that the capital stock numbers are correct. The Company's study of Northeast productivity growth is not accurate enough to predict the normal future growth in gas utility productivity, and it probably understates productivity growth. RR-DTE-76.

The Company continues to cite the same "evidence" regarding differences between the gas industry in the Northeast and in the rest of the country. This "evidence" is biased, for a number of reasons, including the treatment of taxes and the measurement of costs, particularly capital costs. Exh. AG-41; RR-DTE-76. Dr. Kaufman testified that costs in the Northeast might be higher for a number of things, including "labor costs," "frost," "soil," "unionization," "economic growth," and use of "oil for home heating purposes." Tr.26 at 3590-91. He did not mention the possibility that an undervaluation of capital for all Northeast utilities might appear to make the Northeast less expensive than utilities in other areas.

Again, the major reason the capital cost data may be misleading is that the plant data have all been adjusted with simplifying assumptions about vintage. The original adjustment to 1983 data was based on a different factor for each utility, but the difference reflected not different ages of plant among utilities but only the regional differences in the Handy-Whitman index. The 1999 index value varies by construction cost differences. Exh. AG-30-11.

Dr. Kaufman provides an example in his rebuttal testimony to explain how depreciation affects the economic value of capital. The same example, however, can also illustrate how older capital stock may create deceptive results under PEG's treatment. In his example, an older light bulb that has outlasted its expected life is worth "very close to nothing". That older light bulb, however, is still providing value. A business relying on older light bulbs, valued at near zero, would appear to be a lower cost business than the one with newer, more highly valued light bulbs. This disparity will be exacerbated when the plant is cast iron mains, which will be fully depreciated at 40 years when their expected life is 80 years. Tr.9 at 2557. As a result, Boston Gas has plant expected to last another 40 years, which is not reflected in its capital cost. As with the light bulb based businesses, it will appear to be lower cost, and therefore more efficient, than the entity with higher value light bulbs.

An additional problem with the capital cost data, and to a lesser extent with the labor cost data, is the inclusion of actual taxes. The Company cites Dr. Kaufman's response that "cost predictions are also tailored to the company's actual taxes paid." The cost prediction is actually based on taxes paid by all utilities, so that the coefficient will be affected by the average taxes paid, which would make a utility with lower than average taxes appear to be a lower-cost performer than it actually was. Tr. 361-362. The econometric study would have been influenced by the treatment of taxes. The inclusion of actual taxes with costs is not consistent with the theoretical backing of the model[56]. The econometric study is based on a total estimate of capital cost that contains numerous inaccuracies, includes in non-capital costs some costs that are not under the utility's control, does not reflect some important elements of cost causation, and therefore does not prove that Boston Gas is an efficient performer. RR-DTE-76.

In sum, the Company has not clearly established that Northeast productivity growth is less than the nation's, or that, without PBR, Boston Gas can be expected to have considerably

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[56] Exh. KEDNE-LRK-2, Appendix – taxes should be one of components of capital <u>service price</u> index, not capital cost

lower productivity growth than the rest of the economy. These assertions rest on the assumption that a sample of Northeast gas utilities have had lower growth than the rest of the economy, that this condition can be expected to hold in the future, and that Boston Gas cannot be expected to do any better than the average Northeast utilities contained in the sample. The Company has not established that these assumptions and conditions are correct.

The Company's PBR plan is unduly complex and unreviewable, and inappropriate because it suffers from false precision and methodolgical flaws. The Department should reject the Company's proposed PBR plan.

B. THE DEPARTMENT SHOULD REJECT THE PBR BECAUSE THE COMPANY HAS VIOLATED STATUTORY STAFFING LEVEL REQUIREMENTS.

The Attorney General argued that the Company, having filed a new PBR plan, is subject to staffing requirements of the Restructuring Act, G.L. c. 164, § 1E(b)("Act"). The Company claims that statutory staffing level requirements do not apply to it because Boston Gas had a performance-based rate plan ("PBR") on December 1, 1996, before the enactment of the Act. The Company argues that the Act's staffing benchmark is therefore "forever inapplicable to the Company's operations." Co. IBr. at 210, 211. The Company's position ignores basic tenets of statutory construction regarding the plain language of a statute,[57] the intent of the Legislature regarding staffing levels,[58] and the fact that it is now seeking a new PBR–its initial PBR ended in

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[57] A statute is to be interpreted according to the plain and ordinary meaning of its words and their ordinary and approved usage." *Commonwealth v. Colon-Cruz*, 393 Mass. 150, 167 (1984). The "meaning of a statute must, in the first instance, be sought in the language in which the act is framed . . . ." *Boston Neighborhood Taxi Association v. Department of Public Utilities*, 410 Mass. 686, 690 (1991).

[58] "Ordinarily, if the language of a statute is plain and unambiguous it is conclusive as to legislative intent." *Sterilite Corp. v. Continental Casualty Co.*, 397 Mass. 837, 839 (1986). It is the general rule that

2001 by Department order. *Boston Gas Company*, D.P.U. 96-50 (Phase I) at 320 (1996); Letter Order, *Boston Gas Company*, D.T.E. 02-37, August 6, 2002.

If the Legislature had intended to created a permanent exemption from the staffing level requirements, it would have done so. The Act, however, does not authorize the Department to grant a permanent exemption to any company, including Boston Gas. In fact, the Act does just the opposite; it specifically applies to "a distribution, transmission or gas company that makes a performance based rate filing ***after*** (emphasis added) the effective date of this act." G.L. c. 164, § 1E(b). The PBR filing here is a performance based rate filing after the effective date of the Act. The Act's staffing level requirements therefore now apply to the Company.

The Company claims that even if the staffing level requirements apply, "any reductions in bargaining unit staffing levels from that the [sic] level in place as of November 1, 1997, were accomplished in accordance with the collective bargaining agreements executed by the Company and the relevant bargaining units," and that they were done in accordance with an approved PBR in place on November 1997. Co. IBr. at 211. The Company also claims that the employees transferred to the Service Company "remain in the Company's employ and the Company has not reduced those jobs." *Id*. at fn. 88. The Company has provided no evidence that the collective bargaining agreements authorize staffing level reductions below those in place on November 1, 1997. The exemption from the Act's requirements under the old PBR plan expired with that plan in 2001. The Act applies to Boston Gas as a gas company, not to KeySpan's Service Company.

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statutory language is to be "construed so as to effectuate the intent of the drafters of the statute." *McCarthy v. Commissioner of Revenue*, 391 Mass. 630, 633 (1984).

The Act does not provide that a gas company can meet its staffing level requirements through hiring by affiliates.

The Company maintains that, even if its PBR proposal is subject to the staffing level requirements of the Act, the Department is authorized to approve its staffing level reductions if they have not had an adverse impact on the Company's service quality as demonstrated by the record. Co. IBr. at 212. Even though the Department has the authority to approve staffing level reductions after an evidentiary hearing, G.L. c. 164, §1E(b), it cannot do so on this record because the Company did not offer the required evidence.[59] To the contrary, the Company objected vociferously to the Attorney General's efforts to cross-examine the Company regarding staffing levels and service quality, arguing that the issues are not relevant to this case. Tr. 1 at 62-67; Tr. 12 at 1546. After refusing to demonstrate compliance with the staffing level requirements at the hearing, the Company now tries to create a record by testifying in its brief.[60]

The record shows clearly that the Company has engaged in unauthorized reductions in staffing levels. RR-AG-3 [supp]. Because the Company has violated the staffing level service

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[59] The Company is improperly attempting to shift its burden to the Department. The Act clearly places the burden on the Company to demonstrate in an evidentiary proceeding that its staffing level reductions will not disrupt established service quality standards.

[60] The Department does not allow parties to testify in a brief to factual matters not supported on the record. *WMECo*, D.P.U. 86-8C-1, p. 23, n.5 (1986); *AT&T*, D.P.U. 85-137, p. 49 (1985); *AT&T*, D.P.U. 91-79, pp. 5-11 (1991); *Verizon Alternative Regulatory Plan*, D.T.E. 01-31-Phase II, Hearing Officer Ruling Granting Motion Of Attorney General To Strike Portions Of AT&T's Brief, December 19, 2002. In the absence of any supporting citation to the record, the Department should strike the portion of the Company's initial brief (footnote 88 and the sentence preceding it on page 211 through the paragraph that carries over onto page 212) where the Company claims, without record citation, that: (1) since 1997, it has reduced staffing levels only in accordance with collective bargaining agreements; (2) it has consistently met or exceeded Department historical benchmarks; and (3) there has been no adverse effect on the Company's service quality.

quality provisions established under the Act, the Department should reject the Company's PBR and impose a penalty as provided in G.L. c. 164, § 1E (c).

XII. CONCLUSION

WHEREFORE, for all of the foregoing reasons, the Attorney General requests that the Department reject the Company's proposed rate increase.

Respectfully submitted,

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Dated: September 17, 2003